COMPARATIVE STUDY OF TRANSMISSION ALTERNATIVES

BACKGROUND REPORT

CONSULTANT REPORT

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INTRODUCTION

As part of the California Energy Commission's (Energy Commission) collaborative transmission assessment in the 2004 Integrated Energy Policy Report (IEPR) Update, this report presents background information related to transmission alternatives and the transmission planning process. Ultimately, this information will be used to assess potential approaches for evaluating non-transmission alternatives to transmission projects.

The Energy Commission is interested in working with a broad group of stakeholders in the IEPR process, including the California Independent System Operator (CA ISO), investor-owned utilities (IOUs), municipal utilities, federal agencies, local agencies, business groups and environmental organizations to investigate how alternatives are currently considered by various utilities, transmission planning organizations and regulatory authorities. We will consider what preferred approaches are emerging, what considerations are most important to efficiently and effectively deal with issues in California, and how, when and by whom in the transmission planning process should non-transmission alternatives be considered. It is widely recognized among regulatory authorities, industry and the public that a thorough consideration of non-transmission alternatives at the appropriate time in the planning process is vital to a collaborative planning outcome that can pass rigorous environmental review during permitting.

The Energy Commission's objective in this effort is to develop an approach through stakeholder consensus that transmission planners, regulatory authorities, and the public can view as a model approach to assessing alternatives to transmission lines, including non-transmission alternatives. The Energy Commission has put a priority on developing this information through a collaborative process and wants to ensure that all interested stakeholders have an opportunity to participate. This report will summarize existing approaches and ideas and after the June 14, 2004 IEPR Committee workshop, a subsequent report will document the consensus approach expressed by stakeholders that can best serves the needs of California.

This report is based on substantial information gathering and is intended to be expanded based on input from a broad group of stakeholders. Stakeholders may present input at the IEPR Committee workshop to be held June 14, 2004. The report will be used as part of a process in which substantial research and summary information will be consolidated, examined and used by stakeholders and Energy Commission staff to develop a methodology for consideration of non-transmission alternatives to transmission projects. This process is expected to result in information that will feed into future written products that will be defined as work proceeds during 2004.

As background for consideration of non-transmission alternatives, this introduction presents summaries of the purposes of new transmission lines, alternatives to transmission lines, and non-transmission alternatives that are available. It then explains the organization of this report.

Purposes of New Transmission Lines

The fundamental function of new transmission lines is to provide additional electricity to areas of demand or load. Other benefits provided by additions to the transmission system include:

- Improving system reliability by providing redundant pathways that could serve load if one pathway were out of service
- Reducing transmission congestion and improved the transmission efficiency in areas where existing lines have inadequate capacity to carry electricity
- Reducing the cost of electricity by avoiding congestion penalty fees, allowing additional sources of power generation to reach an area of load, and/or reducing the need for mandatory power generation at “must-run” facilities.

Problems in Transmission Line Siting and Permitting

Fast-paced growth in California has caused an increased need for electricity to be provided to population centers, but it has also created constraints on the land available for installation of major transmission lines. The most serious issues and concerns that typically arise in siting of transmission lines are:

- Availability of transmission corridors leading into and through developed areas,
- Visual impacts of transmission lines,
- Electric and magnetic field (EMF) concerns for adjacent land uses, and
- Other environmental effects (e.g., biological, cultural) of line installation.

Alternatives to Transmission Lines

When an inadequacy is identified in the power transmission grid, the problem can often be solved in a variety of different ways. The installation of a new transmission line to move electricity from one place to another is one way of solving that problem. However, at various points in the transmission planning process (usually at least during pre-application project planning and in the consideration of a proposed project under the California Environmental Quality Act, CEQA), alternative means of solving the problem are considered. These options generally include the following:

- Different transmission line routes, different tower designs, and installation of lines either overhead or underground. All of these options are still transmission lines, but with varying types and extents of environmental impacts and widely varying cost.

- Generation (if properly located) can reduce or eliminate the need for transmission lines. Generation includes gas, coal, or nuclear-powered power plants, as well as renewable energy technologies (solar, wind, geothermal, biomass, hydro, and tidal power).
- Electricity storage could reduce the need to import power to an area of load.
- Conservation (demand-side management) can reduce demand for power, thus reducing or eliminating the need for new transmission lines.

Because the focus of this effort is to consider non-transmission alternatives, the first bullet above (transmission line design or routing alternatives) will not be evaluated in this study. Each of the other topics is summarized below and addressed in more detail in Chapter 2 of this report.

Summary of Non-Transmission Alternatives

Strategic Generation

Locating power generation facilities near load centers reduces the need for long-distance transmission facilities. Populated load centers, however, are not normally well-suited for large scale power plant development, and siting such facilities is a complex process. The environmental concerns for generation facilities commonly include adverse effects related to air pollution, water pollution, hazardous materials handling, noise, and aesthetics. In some circumstances, small-scale generation facilities (e.g., distributed generation) or facilities powered by renewable resources can minimize the environmental effects of generation while satisfying local loads without the need for extensive transmission expansions. New generation development in strategic locations is critically dependent on the participation of willing project sponsors, the local availability of energy resources, and the local attitude toward development.

Demand Management

Load reduction can also reduce or postpone the need for long-distance transmission facilities. Reducing demand normally involves voluntary participation of electricity consumers, but in extreme circumstances load can be shed by dropping industrial customers with interruptible rate contracts or through forced power outages. The common options for alleviating the load on transmission facilities include energy conservation (i.e., demand side management or DSM) or load shifting (i.e., timing loads to occur during non-peak hours). The success of demand management depends on scope of participation, which is influenced by economics and convenience.

Transmission Pricing Strategies

Transmission grid operators can use pricing strategies to provide incentives for transmission system improvements. Although this approach would not directly change the demand for power or its supply, altering the economics of power delivery to loads can provide strong incentives for system improvements. Transmission fees may be instituted by the grid operators, but they may be subject to rigorous oversight by regulators at the state and federal levels.

Organization of this Report

This report contains four main sections, focusing on the following topics:

- The first section describes the non-transmission alternatives that are currently available for consideration, and briefly explains the status of each technology.

- The second section describes the process that has historically been used to consider transmission alternatives, and presents some examples of transmission projects that have moved through this process.

- The third main section presents preliminary recommendations on where in the process alternatives to transmission should be considered,

- The final section begins a discussion of methodologies that could be used for consideration of alternatives.

The last two parts of this report will be the focus of discussion at the June 14, 2004 IEPR Committee workshop.

The Appendix to this report includes background on various CA ISO, California Public Utilities Commission (CPUC), and Energy Commission proceedings and processes, as well as references and a list of abbreviations and acronyms.

WHAT ARE THE ALTERNATIVES TO TRANSMISSION?

According to the state Energy Action Plan jointly written by the Energy Commission, CPUC, and California Power Authority (CPA), the state currently uses 265,000 gigawatt-hours (GWh) of electricity per year (Energy Commission et al., 2003). Consumption is growing two percent annually. Peak demand is growing at about 2.4 percent per year, roughly the equivalent of three new 500 megawatt (MW) power plants each year. This demand will need to be met by increased generation, but generation cannot always be located in areas of greatest demand so transmission of power is required. Major transmission lines are increasingly difficult to site, so consideration of other alternatives is critical.

Non-transmission alternatives (also called “non-wires” alternatives) are those that do not involve major new transmission lines and are one way to respond to this load growth. Renewable energy and fossil fuel generation, if they can be produced near the location where they would be used, are potential non-wires alternatives. In addition, DSM or conservation, electricity storage, and distributed generation (DG) can reduce the need for a transmission project and thus are also considered as non-wires alternatives.

This section presents a summary description and describes the technical status of alternatives to transmission (and subsequent need for some of these alternatives to also require additional transmission), such as generation, renewables, electricity storage, and conservation/DSM.

Generation Summary and Types

During the first three decades of the 20th century, hydroelectric power plants were the state’s main source of electricity. Hydroelectric development continued in all decades, peaking in the 1960s. Oil-fired power plant development began in the late 1930s and peaked in the 1950s and 1960s. The oil shortage and air quality concerns of the 1970s caused these plants to switch to natural gas (keeping oil as a back up fuel to use when gas supplies were short).

A few nuclear power plants were added to California’s utility system beginning in the late 1960s through the 1980s. Policies to increase the diversity of primary energy sources for electricity generation in the 1970s and 1980s led to the development of geothermal, wind, waste-to-energy, and solar energy facilities as well as cogeneration plants fueled by natural gas and coal.

Post-1996 power plant development in California has consisted almost exclusively of natural gas-fired simple-cycle combustion turbine power plants and combined-cycle combustion turbine facilities, including the expansion or repowering of older thermal power plants (Energy Commission, 2001).

In 2004, almost one third of California's entire instate generation base is over 40 years old. While in-state generation resources provide the majority of California's power, California is part of a larger system that includes all of western North America. Fifteen to 30 percent of statewide electricity demand is served from sources outside of the state (Energy Commission et al., 2003).

Table 1 illustrates the sources of power generation currently used in California (in-state generation only), and the percentage of each as a component of total electricity used.

Table 1. Sources of Power Generation in California

Type	MW
Gas-fired power plants*	Over 30,000
Hydroelectric	14,116
Nuclear	4,310
Wind	1,818
Solar thermal	409
Geothermal	2,626
Coal	560
Waste-to-Waste	1,071
Energy efficiency and DSM savings	8,700
Total Generation Capacity	55,800

Sources: Energy Commission, 2001 and 2003c.
* Includes the 6,986 MW of capacity permitted by the Energy Commission and 1,372 MW of capacity of smaller, locally permitted projects that have been added to the system since 1998 (CEC, 2003c)

There are four basic types of electricity generation: baseload suppliers, intermediate load plants, peaking plants, and distributed generation.

- **Baseload generation**. A baseload electricity generating facility typically houses high efficiency steam-electric units and is normally operated to take all or part of the amount of electric power that is required to meet minimum load demands of the system based on reasonable expectations of customer requirements. It consequently produces electricity at an essentially constant rate and runs continuously. Baseload units are operated to maximize system mechanical and thermal efficiency and minimize system-operating costs. Nuclear, coal-fired, and geothermal power plants are run in baseload mode. In addition, hydroelectric power plants with continuous water flows, and cogeneration plants also operate in this mode.
- **Intermediate load generation**. Load following is the utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility, and/or keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utility's customers. Intermediate load generation generally supplies electricity for parts of the day that represent pre-determined, repetitive requirements, such as lights at night. The intermediate or load-following suppliers are often older and less efficient plants than baseload plants and require high levels of maintenance, and, therefore, have higher operating costs than baseload plants.
- **Peaking power plants** are typically gas- or oil-fired plants and are typically used only when the level of demand reaches its maximum (or, for one reason or another, when the supply-demand balance is very tight). Peaking plants may

house old or low-efficiency steam units, gas turbines, diesel generators, or pumped storage hydroelectric equipment, any of which may be used during the peak-load periods.

- **Distributed generation (DG)** is the generation of electricity from facilities that are smaller than 50 MW in net generating capacity. DG allows customers to choose between electricity supplied via traditional utility grid service, electricity provided by a non-utility generator located at or near the point of consumption, or by some combination of the two. Most DG facilities are very small. For example, a fuel cell can provide power in peak demand periods for a single hotel building. More than 2,000 MW of DG is now in place in California.

Fossil Fueled Power Plants

Gas-Fired Turbine Power Plants. Over half of California's power generation is from gas- and oil-fired power plants. These plants can be located wherever there is adequate industrial land, supplies of natural gas, and water for cooling. Transmission lines are required if plants are not located in or near load centers. However, siting plants near load centers can be difficult due to the potential environmental impacts of these facilities. Air emissions, noise, water use, and visual impacts are generally among the most difficult environmental issues in siting power plants.

Siting of new power plants requires approximately 14 months of Energy Commission review after an Application for Certification is submitted to the Energy Commission, assuming the AFC is found to be complete (California Energy Commission Power Plant Permitting Timeline; Energy Commission, 2000). Preparation of an AFC by the applicant can take a year or more.

Fuel Cells. Fuel cells are devices in which the energy of a chemical reaction is converted into electricity. Fuel cells produce direct current (DC) electricity from the electrochemical potential created by a fuel (i.e., hydrogen) and an oxidizer (i.e., oxygen). Fuel cells are similar in construction and operation to batteries, but are designed to minimize electrode sacrificing and are continuously fed reactants. Unlike a battery, a fuel cell does not run down or require recharging; it operates as long as the fuel and oxidizer are supplied to it. Fuel cell power plants have ultra-low air emissions and can perform at high efficiency even in relatively small capacity.

Fuel cell power plants require a fossil fuel to operate and thus must be located where an appropriate fuel can be delivered. Seventeen 200 kW fuel cell systems are installed or under development at California military bases and commercial customer facilities. Near-term plans include the installation of at least four 300 kW fuel cell power plants at California utility customer locations. A one MW fuel cell plant is installed at a Washington state sewage treatment plant.

Electricity Storage

Energy storage can be used to balance fluctuations in the supply and demand of electricity. Although it cannot replace generation, it can complement other forms of generation. A storage plant can be used in a distributed role by being charged during off-peak periods and the energy generated would then be used during peak periods. Storage can also be used to provide frequency response, rapid response, black start and other services (Price et al., 2000). Electricity storage units are usually located as close as possible to the end consumer of electricity.

Renewable Energy Options to Transmission

In this renewable energy generation sources are described so their relevance as transmission alternatives can be considered. The renewable technologies described here include the following:

- Solar thermal power
- Solar photovoltaics
- Wind
- Geothermal
- Hydropower
- Tidal power
- Biomass

Overview of Renewable Energy

In the year 2002, California had over 7,000 MW of renewable energy capacity, including solid-fuel biomass, geothermal, wind, small hydroelectric (30 MW or less), concentrating solar power (CSP), photovoltaic systems (PV), landfill gas, digester gas, and municipal solid waste (MSW) facilities (Energy Commission, 2003). These facilities produced about 28,900 GWh in 2002, about 11 percent of the electricity used in California.

Table 2. California Renewable Capacity in 2002

Renewable Resource	MW Capacity
Wind	1,618 MW
Biomass and Waste	1,016 MW
Solar	387 MW
Hydroelectric	14,116 MW
Small Hydro (30 MW or less)	1,293 MW
Geothermal	2,735 MW

Source: Energy Commission, 2003.

In-state renewable capacity in 2002 is listed in Table 2. Much of California's existing renewable capacity is old and inefficient, especially wind and geothermal facilities. Uncertainties exist as to whether much repowering would take place in the future. Renewable resources available out-of-state are constrained by the fact that many of the resources are located far from population centers and existing transmission lines. In addition, the generation of power outside the state would only increase the pressure on California's transmission system..

California's existing transmission system would need to be expanded to accommodate instate development of renewable energy resources. However, energy providers subject to the Renewable Portfolio Standard (RPS; see discussion in Appendix) may choose to buy renewable power generated out-of-state. The degree to which such purchases occur would affect transmission expansion requirements. Meeting some of the RPS requirements through distributed generation or by repowering of wind and/or geothermal facilities could also reduce the need to install new transmission lines. However, added generation could also aggravate congestion.

The following sections summarize the current status of renewable technologies that could serve as alternative to major transmission lines: solar thermal, solar photovoltaic, wind, geothermal, hydropower, biomass, and tidal power facilities.

Description of Renewable Technologies

Solar Thermal Power

Solar thermal power generation, also known as concentrating solar power, involves the conversion of solar radiation to thermal energy, which is then used to run a conventional power system. Solar thermal is a viable alternative to conventional energy systems and, depending on the particular technology, is suited to either distributed generation on the kilowatt (kW) scale or to centralized power generation on scales up to several hundred MW. Solar thermal systems utilize parabolic trough concentrating collectors, power tower/heliostat configurations, and parabolic dish collectors. Parabolic trough systems typically run conventional power units, such as steam turbines, while parabolic dish systems power a small engine at the focal point of the collector.

Parabolic trough plants are operating commercially today on a large scale. There are currently nine trough systems located in the Mojave Desert, generating 354 MW of peak power. These systems have excellent performance, even after 10 years of operation. Over 9 million MW-h of electrical power have been produced by these solar plants. Many of the plants have consistently met or exceeded design outputs during crucial peak power periods. Arizona Public Service broke ground in March, 2004 on a 1 MW solar trough facility, the first such facility built in the United States since 1988 (Barber, 2004b).

The larger grid-connected plants are normally sited in semi-arid areas with a high solar resource and reasonable proximity to transmission lines. Smaller trough plants and dish-engine systems can be placed in many areas near industrial and commercial development.

Although significant improvements have been made in technology advances and cost reductions, additional research and development is needed for concentrating solar power to be cost-competitive with conventional fossil fuel plants. Solar thermal facilities will likely not come into play until the 2008-2017 timeframe (Energy Commission, 2003a).

Solar Photovoltaic Power

Solar photovoltaic (PV) power generation uses special semiconductor panels to directly convert sunlight into electricity. Arrays built from the panels can be mounted on the ground or on buildings where they can also serve as roofing material. When large collections of PV panels or modules are put together, they can be tied into the electricity grid system. Electricity generation from solar technologies, including both photovoltaic and solar thermal systems, currently totals about 0.3 percent of the state's electricity production. Maximum power output of PV systems closely matches California’s peak electrical demands. The intermittent nature of the power, however, makes PV systems unsuitable for base-load applications.

PV power systems require approximately one acre per 250 kW at 50 percent area coverage and 10 percent system efficiency. Systems up to about 250 kW are often placed on buildings, and are commonly referred to as building-integrated PV or dual use systems. For systems larger than 250 kW, ground-mount installations are more common. Ground-mount sites require environmental impact reviews because in order to achieve power levels comparable to conventional fossil-fueled peaking combustion plants, large areas are required. For a 50 MW system, over 200 acres would be required. This could be achieved as a single system or as a number of smaller systems distributed on building roofs, covered parking structures, or similar “community integrated” deployments.

The largest system ever installed in the U.S. was put in by Siemens Solar (formerly Arco Solar) at Carissa Plains, CA, which was rated at 6 MW and has since been dismantled. The cities of San Diego and San Francisco are aggressively pursuing the increased use of solar PV power in their jurisdictions.

Wind Power

Wind is an abundant form of energy that is generated through solar heating of the earth’s atmosphere. It carries kinetic energy that can be utilized to spin the blades of a wind turbine rotor and an electrical generator, which then feeds alternating current (AC) into the utility grid. Most state-of-the-art wind turbines operating today convert 35 to 40 percent of the wind’s kinetic energy into electricity.

Several utility-scale turbines are typically installed in a “wind farm” that is operated as single power plant. The usual mode of operation of wind farms is as an intermittent, variable resource. The annual power production profile for California’s existing wind farms corresponds to seasonal demand consumption patterns. The match to daily demand peaks is less correlated.

Modern wind turbines represent viable alternatives to large bulk power fossil power plants as well as small-scale distributed systems. However, their intermittent power makes them unsuitable for base-load applications. The range of capacity for an individual wind turbine today ranges from 400 watts up to 3.6 MW.

Today's utility-scale 1.5 MW wind turbines typically operate 35 to 40 percent of the time in wind resource regions. A single 1.5 MW turbine operating at a 40 percent capacity factor generates 2,100 MWh annually. The average capacity of wind turbines today is 750 kW. Wind turbines of 1 or 2 MW are becoming more common, and even larger ones of up to 6 MW are under development.

California's 1,700 MW of wind power represents only 1.5 percent of the state's electrical capacity and less than 10 percent of the global market. There are four primary wind resource regions in California that feature commercial development: the Altamont Pass (582 MW), Tehachapi (620 MW), San Gorgonio (355 MW), and the Montezuma Hills (60 MW). Pacheco Pass also has a small number of turbines generating less than 2 MW.

Wind farms are more constrained geographically than other renewables. However, wind resource areas in California are located strategically throughout the state, ranging from San Diego in the south, to Humboldt County in the north. California actually has good wind resource areas located relatively close to load centers and dispersed north and south, east and west. This diversity of wind resource areas enhances the desirability of this renewable technology when looking at alternatives to natural gas-fired power plants.

The state's existing wind capacity is old and less efficient than today's turbines and may present an opportunity for repowering. The new wind turbines being installed in the Solano Wind area have twice the generating capacity as the older units and can produce power at lower wind speeds. They also can run at higher wind speeds — up to nearly 60 miles per hour. A computer in the turbine responds to changes in wind velocity by changing the angle of the blades for maximum power generation. The bigger turbines also have less environmental impact. Because the blades turn slower, it's easier for birds to see the blades and avoid flying into them. The new turbines also have pedestal towers, which means birds are not able to perch or roost near the blades. However, the lack of available transmission access, especially in the Tehachapi area, is an important barrier to wind power development.

Both the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) are aggressively pursuing wind power to supplement electricity resources for their areas.

Geothermal Power

Geothermal power plants use high-pressure steam and hot water from naturally occurring deep geothermal reservoirs. Dry steam and flash plants use the force of steam to drive turbine generators and generate electricity. In binary plants, hot water is pumped through a heat exchanger to heat and vaporize a second (binary) low-boiling-point working fluid that drives the turbine. The plant design is determined primarily by the temperature of the reservoir. In all plants, used water and steam condensate are injected back into the periphery of the reservoir to sustain production.

Geothermal plants account for approximately five percent of California's power, and range in size from under 1 MW to 110 MW. Geothermal plants typically operate as base-load facilities and require 0.2 to 0.5 acre/MW. California is the largest geothermal power producer in the United States, with about 2,560 MW installed gross capacity and 1,754 MW net capacity (Energy Commission, 2003a). Geothermal plants provide highly reliable base-load power, with capacity factors from 90 to 98 percent.

The geothermal industry has identified 2,655 MW of potential new development in California within the next two to five years (Carter, 2004). The United States Geological Survey reports the potential in California as about 12,000 MW and an update of that assessment has begun.

Geothermal plants must be built near geothermal reservoir sites, because steam and hot water cannot be transported long distances without significant thermal energy loss. Geothermal power plants are operating in the following California counties: Lake, Sonoma, Imperial, Inyo, Mono, and Lassen.

Geothermal power may experience growth over the next 10 years. The extension of the Production Tax Credit through the Energy Bill along with RPS will determine the size of the growth. RPS will also encourage the development of geothermal energy by adjacent states, such as Nevada and Oregon, for sale into California. In addition, the Energy Commission held a meeting on May 20, 2004 for a California Geothermal Summit to form a California geothermal collaborative.

Today, geothermal energy is nearly competitive with conventional power options and can provide high capacity factors of greater than 90 percent with no intermittency issues. The gross capacity of The Geysers, located in Sonoma and Lake Counties near the City of Santa Rosa, is currently about 1,700 MW from 21 power plants. PG&E constructed the first U.S. geothermal plant at The Geysers in 1960. Today The Geysers area is fully developed and there are no known plans for new construction. However, repowering of some plants is planned at The Geysers, which remains the largest steam field in the world and the only dry steam field in the United States.

Transmission interconnection costs, as well as the cost of transmission upgrades, would be significant as new areas are developed and existing areas are expanded. Geothermal projects have fairly high capital costs, as compared to many other power generation technologies. New plants that are expansions of fields, such as in the Imperial Valley, will be less expensive than the construction of geothermal plants in new fields. This aspect has been a deterrent for some developers. The total capital cost to build a 25 to 50 MW flash plant in today's market varies from about \$2,100/kW to \$2,600/kW. The capital costs of developing 10 to 30 MW binary plants range from $3,000/kW to $3,300/kW. Many factors dictate the ultimate capital costs including resource temperature and chemistry, productivity of each well, size of the facility, type of terrain, H_2S abatement requirements, etc. The turbines are generally custom made (from standard frame sizes) to match the characteristics of the resource and the design approach to the other major plant equipment.

Hydropower

Hydroelectric power uses the energy of falling water to turn turbines and generate electricity. Power production increases with both greater water flow and greater fall. California has 386 existing hydro generating units making up an installed capacity of 14,116 MW and representing 26 percent of the installed capacity in the state. In California, gross capacity ratings for hydroelectric generating units vary from less than 100 kW for some small distributed generation systems to in excess of 400 MW, such as for each of three units (1,200 MW total) at PG&E's Helms Pump Storage Powerhouse on the North Fork Kings River. Hydropower currently provides 15 percent of the state's electricity production, generally in base-load applications.

Pumped storage projects operate much like storage projects, with the added benefit of recycling water for reuse. Usually staged between two reservoirs, pumped storage powerhouses generate power during peak hours and pump water back to the upper reservoir during off-peak hours. The power required to pump water from the lower to the upper reservoir exceeds the power generated when water from the upper reservoir is allowed to flow through the turbine and back into the lower reservoir. However, pumped storage projects can release upper reservoir water to meet peak load demands, and it is at these times when power is valued the highest. Pumped storage systems can thus provide a net economic benefit.

Opportunities for new hydropower dam and storage projects are extremely limited in California due to a lack of sites, lack of availability of unallocated water rights, environmental protection measures (i.e., Wild and Scenic Rivers, Endangered Species, and Wilderness Area designations), and strong political opposition. New development requires an approximate 10-year timeframe in order to plan and understand the potential environmental effects and prepare appropriate environmental safeguards. However, opportunities for incremental development, such as adding or improving generation facilities attached to existing dams, water conveyance facilities, and powerhouses remain a viable option for increasing hydropower production in California.

Hydroelectric development in California is primarily located in the mountainous regions of the state. These include the Sierra Nevada and the northern and southern California Coastal Ranges.

Tidal Power

Tidal power uses the gravitational pull of the moon to harvest energy from the difference between high and low tides greater than 5 meters (16 feet). Wave power extracts energy directly from the surface waves; wave power along California coast waters could produce between 7 and 17 MW per mile of coastline. Ocean thermal energy conversion uses the temperature difference between water layers to generate power. Cost and performance uncertainties limit its potential near-term use. However, unlike the sun and wind, tidal current is consistent and predictable. Tidal generators could produce electricity up to 16 hours a day. The largest existing plant is a 240 MW plant in France. No tidal plants exist today in the United States, but there is a pilot project proposed in San Francisco (San Pablo Bay area) that would be the first working project in the United States to test tidal power. Tidal energy is costly and could pose significant environmental impacts to marine resources.

Biomass Power

Biomass electricity is generated by burning organic fuels in a boiler to produce steam, which then turns a turbine. Biomass can also be converted into a fuel gas such as methane and burned. Wood is the most commonly used biomass for power generation. Currently, 2.2 percent of the state's electricity derives from biomass and waste-to-energy sources. Most biomass plant capacities are in the 3 to 10 MW range and typically operate as base-load capacity. Unlike other renewables, the locational flexibility of biomass facilities would reduce the need for significant transmission investments. The total California plant operating capacity is about 610 MW, and the idle capacity is about 122 MW. A number of biomass plants have been dismantled (CBEA, 2003).

Distributed Generation

There are many DG technologies, including microturbines, internal combustion engines, combined heat and power (CHP) applications, fuel cells, photovoltaics and other solar energy systems, wind, landfill gas, digester gas and geothermal power generation technologies. They may be combined with electric storage technologies such as batteries and flywheels. DG units may be owned by electric or gas utilities, by industrial, commercial, institutional or residential energy consumers, or by independent energy producers.

In addition, there are several incentive programs designed to provide financial assistance to those interested in operating DG systems in California. Senate Bill 1345 (Statutes of 2000, Chapter 537, Peace, signed by Governor Davis in September 2000) directs the Energy Commission to develop and administer a grant program to support the purchase and installation of solar energy and small DG systems. These systems currently rely on incentive programs and government support to offset their higher costs. An exception would be those DG installations that provide a higher quality of power or a more reliable power supply than can be provided by the electric utility company and for which businesses are willing to pay extra.

The Energy Commission in collaboration with the CPUC instituted an investigation (Docket 04-DIST-GEN-1, 03-IEP-1) exploring issues associated with implementation and distribution planning of DG. The main objectives of this investigation are to examine the costs and benefits of DG deployment, interconnection related issues, and research and development efforts related to the technical, economic and regulatory feasibility of future distributed energy resources (DER) technologies. The results of this investigation are expected to be a series of recommended changes to the rules of the CPUC, IOUs planning processes, and will be incorporated into the 2005 IEPR.

This investigation supports a companion Order Instituting Rulemaking (OIR) opened by the CPUC on March 16, 2004 (CPUC Docket R.04-03-017). The CPUC's OIR is intending to update the record in its previous predecessor DG rulemaking, R.99-10-025, take a broader look at the reality and potential of DG deployment, and allow the CPUC to make informed decisions from a base of facts representing existing economic, technical, and environmental conditions associated with DG deployment. Topics for the OIR include cost-benefit analyses for customer and investor-owned utility installations; DG as a utility procurement resource; future incentives for customer-side DG; outstanding interconnection and related technical issues; and, DG issues for the future.

Relating to the CPUC OIR, the Energy Commission will lead the effort to explore potential revisions to the current interconnection rules, explore progress of public interest research and development associated with future DER technologies, and assist the CPUC with the development of a cost benefit analysis for deployment of DG. The Energy Commission's Order Instituting Investigation will commence with a staff workshop that will focus on the cost-benefit analysis component of the investigation, as well as a discussion of the roles and responsibilities of the CPUC and the Energy Commission for the complementary proceedings.

Formal recommendations on these topic areas will be provided to the CPUC and other entities in a manner that accommodates the CPUC's OIR schedule.

The CPUC and Energy Commission received comments on the value of DG, including costs and benefits. The Energy Commission and CPUC then conducted a joint workshop to discuss issues relating to cost and benefit methods for DG on May 5, 2004.

Demand Management Options

Reducing electric demand can defer the need for transmission lines for varying periods of time. Demand can be reduced through broad strategies that encourage energy efficient appliances and public awareness, to highly technical Internet-based technologies that manage peak load.

Conservation/Demand-Side Management

DSM includes a variety of approaches, including energy efficiency and conservation, building and appliance standards, load management and fuel substitution. Since 1975, the displaced peak demand from all of these efforts has been roughly the equivalent of eighteen 500 MW power plants. The annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more new buildings and homes are built under increasingly efficient standards. Savings from energy efficiency programs implemented by utilities and state agencies have also increased (from 750 to 3,300 MW). During the summer of 2001, between 70 to 75 percent of the peak load reductions came from consumer conservation efforts, while 25 to 30 percent came from energy efficiency investments (Energy Commission, 2003).

Load Shifting and Load Shedding

Load shedding is a controlled interruption of electric supply to customers, usually due to temporary shortage of supply. Load shedding is rare, not normally preferable, and most commonly applied during times of emergency or severe shortage, such as during the California Energy Crisis in 2001. During these situations the CA ISO determines how many MW need to be removed to maintain system integrity and to keep the system stable.

Without rotating outages when supplies are low, the entire electric system can become unstable and the whole system could be lost. Therefore, the purpose of an outage is to take a planned or intentional outage to a small part of the grid in order to preserve the integrity of the other large portion of the grid. During rotating outages a block of customers is out for a period of time, typically about an hour, and then that block changes to the next block of about the same size. The CA ISO does not determine who is out of power. The CA ISO only communicates the number of MW or the size of the reduction needed to keep the electrical system intact.

The IOUs have outage programs set up to deal with emergencies, such as earthquakes or other system or equipment failures. Load-shedding equipment/buttons that are pressed to drop large blocks of load are a part of any utility operation to prepare for emergencies. In most cases, the first loads a utility will shed in these conditions are loads required by industrial and commercial customers. Institutional loads are typically the last to be shed since public institutions (hospitals, schools, municipal lighting authorities, etc.) are considered to be a utility's most essential customers. Voluntary load shedding can be used to avoid rotating outages.

Load shifting is a fundamental demand-side management objective. It is the practice of altering the pattern of energy use so that on-peak energy use is shifted to off-peak periods. Incentives can include programs such as receiving lower prices of energy through "time-of-day" rates offered by the electric utilities, but it is difficult to predict the voluntary load shifting by customers. While load shifting and other DSM measures are important for operation and are incorporated into its system base and peak load forecasts, the available energy savings from these programs are generally insufficient to be used as a stand-alone alternative to transmission.

Economic Incentive Options

The transmission system operator can penalize transmission owners for inefficient use of the grid. For example, certain generation facilities may be required to run for transmission system reliability (see reliability must-run (RMR) discussion in the Appendix), which reduces the flexibility and efficiency of the open market. Fees that penalize transmission owners for excess congestion or interconnection access to the transmission system can also provide economic incentives for improving the transmission system. The following section describes some of the strategies that influence the economics of system additions.

Reliability Must-Run Obligations

In many cases, certain generation-related components, in whole or in part, complement transmission-related components. Generation-related components benefit the transmission grid in several ways, including: providing voltage support, reducing heavy power flows on certain transmission lines, and minimizing the oscillatory nature of the electric system (CA ISO, 2003c). In these situations, generation and transmission facilities are interdependent in maintaining grid reliability. A generating unit, whose absence could have a detrimental impact on reliability in a discrete local area under specified operating conditions, is categorized as a RMR generating unit.

RMR constraints can be the result of either the location of a power plant or its operating characteristics. The location of a plant may make it an indispensable provider of reactive power, necessary to maintain the stability of the electric system. Location in a transmission-constrained area may also require that the plant operate in order to guard against the possibility that the failure of another plant or a transmission line could cause a collapse of the system. In addition, some power plants, such as nuclear facilities, run-of-river hydro facilities, and ‘slow-start’ steam turbines, cannot reduce output because of the physical and economic costs of doing so (Energy Commission, 2003c).

Must-take’ plants are those whose output must be purchased due to contractual obligation (e.g., qualifying facilities), because the output of the plant cannot be controlled short of a complete shutdown (e.g., wind and solar facilities), or due to physical or environmental constraints (e.g., run-of river hydro).

Each year the CA ISO publishes a RMR Study Report, which details the CA ISO’s technical studies that were performed to identify RMR requirements and RMR generator unit candidates for the upcoming year. The assessment process includes investigation into potential RMR-related reliability impacts in local areas that are internal to the CA ISO Controlled Grid.

Congestion Fees

Congestion in energy transmission systems occurs when local demand for energy approaches the limits of the transmission system's ability to supply it. Congestion management is a major function of any transmission operator, and it is an active process that ensures the transmission system does not violate its operating limits. With electric energy restructuring, the congestion management has become extremely important and if not properly implemented, it can impose a barrier to trading electricity.

The restructuring process in the electric power industry has led to many structural and regulatory issues regarding grid operation and planning that were not anticipated during original development of the grid. Improvements to the transmission system tend to respond to the needs of increasing demand and deregulated generation, rather than foreshadow them. This has caused somewhat unexpected congestion bottlenecks in the system. Moreover, the unbundling of generation and transmission functions during deregulation led to decreased coordination between the developers of generation and the transmission system operator. In order to effectively manage the transmission system, monitor transmission market activity, and identify areas where expansion would be economical, the transmission operator must be able to accurately forecast and assess the magnitude of congestion rent revenue.

Currently, the CA ISO allocates congestion rent to the transmission owners and the excess/shortfall is paid to/collected from the transmission owners. The CA ISO congestion management process uses 26 zones or geographical locations to define electrical characteristics of the power grid and determine a financial value for the ability to serve its energy needs. Congestion management through zonal pricing follows the topography, operation, and pricing of the transmission network.

When the amount of power scheduled for delivery into the California market exceeds the capacity of the system's transmission lines, the CA ISO makes "congestion payments" to market participants that either schedule transmission in the opposite direction or reduce their generation/load schedule. Congestion rent is collected by the CA ISO from generators who must pay more to use the grid on congested lines.

Fees for Transmission Losses or Access

Transmission losses occur during any delivery of power from a generator to the load. Accordingly, grid operators normally charge a fee for transmission loss for every transaction. The transmission customers (either the power customers or suppliers) pay the fee for transmission losses, which depends on the relative locations of the points of power delivery and withdrawal on the grid. Depending on the market design followed by the grid operator, these charges may be explicitly assigned to zones or they may be implicitly reflected in location-specific prices for transmission system use. The CA ISO currently sets these charges depending on the grid zone location of where the generating unit accesses the grid.

The economic viability of contracts between power suppliers and loads can be drastically influenced by the charges for losses or access established by the grid operator. These charges are normally structured to provide economic advantages to power generators located near critical loads and to discourage locating generating units far from the loads.

Conclusion

Table 3 summarizes generation technologies and their major capabilities and constraints.

Table 3 Summary of Generation Alternatives to Transmission

Technology	MW of individual facilities or fields	Location-Dependent?	Other constraints?
Gas-fired turbines – peakers	50 MW	no	Can be difficult to site in developed areas
Gas-fired turbines – combined cycle	100 – 1000 MW	no	
Fuel cells	up to 1 MW	no	Developing technology
Solar thermal	small to 100 MW	yes	Requires large land area & maximum thermal radiation
Solar photovoltaics	250 kW on buildings; up to 6 MW in field	no	Small scale installations at relatively high cost
Wind	up to 4 MW	yes	Geographic siting – requires transmission to get to load
Geothermal	up to 110 MW	yes	Geographic siting – requires transmission to get to load
Hydroelectric	up to 400 MW	yes	Unlikely that new facilities can be approved
Tidal	up to 240 MW	yes	New technology not applied in U.S.
Biomass	up to 10 MW	no	Requires access to fuel

As summarized in Table 3, there are several solutions for local generation that can produce electricity in the range of a few kW to a few MW. These technologies have important applications in reducing growth in demand on transmission lines and on large fossil fueled power plants. They can defer the need for new transmission lines by a year or two. However, the scale or status of some of these technologies does not allow all technologies to serve as effective alternatives to transmission lines that can move from 200 to 1,000 MW from one area to another. Other technologies have constraints in that they must be located in specific geographic areas where the resource is available, requiring transmission to transport electricity to areas of demand.

In order to replace a major transmission line, a portfolio of these technologies may be required. The development of such a combined package will require active coordination in the planning stages.

HOW HAVE ALTERNATIVES TO TRANSMISSION HISTORICALLY BEEN CONSIDERED?

The following three sections, present an overview of the current process for evaluation of transmission lines; describe the CA ISO's operational processes and planning processes as they relate to transmission lines; and describe existing processes for evaluating and comparing alternatives.

Timeline / Flowchart Illustrating Current Process

Table 4 describes the current process under which major transmission projects for Investor-Owned Utilities (IOUs) are developed and evaluated.

Table 4. Timeline of the CA ISO Transmission Assessment and Planning Process for IOUs

Step #	Timing	Responsible Party	Process or Milestone	
1	Year 0-1	IOU with CA ISO/Study Group	IOU Annual Transmission Grid Expansion Plan	• Focuses on years +1-5 for reliability • Focuses on years +6-10 for 230 kV and 500 kV systems • Evaluates non-transmission alternatives to postpone expansions or improve system efficiency (market-level)
2	Year 1-2	CA ISO	CA ISO Annual Controlled Grid Study	• Identifies major expansion recommendations • Allows determination of need by CA ISO
3	Year 1-2	CA ISO	CA ISO Determines Need	• Initiates coordination with WECC and SSG-WI • Establishes need relative to Grid Planning Standards
4	Year 2-3	IOU	IOU Develops and Submits CPCN Application and Preliminary Environmental Assessment	• Contains preliminary assessment of possible route options and design alternatives to reduce environmental impacts
5	Year 3-4	CPUC and IOU with public participation	CPUC CPCN and CEQA Processes	• Evaluates alternatives, including possible non-transmission options, to reduce environmental impacts (project-level)
6	Year 4	CPUC and IOU with public participation	CPUC Issues CPCN	• Establishes need relative to environmental consequences
7	Year 4	IOU with Stakeholders	IOU Final Design and Permitting	• Allows minor adjustments to route or design to respond to environmental conditions (site-level)
8	Year 5	IOU with CPUC oversight	IOU Constructs Project	• Project operational roughly four years after closure of original expansion planning process

Table notes:
WECC: Western Electricity Coordinating Council
SSG-WI: Seams Steering Group-Western Interconnection
CPCN: Certificate of Public Convenience and Necessity (CPUC permit issued for major transmission projects)
EIR: Environmental Impact Report (standard environmental report for major projects under CEQA)
Assumptions:

- Annual Grid Expansion Planning Process (12 months duration)
- CA ISO Need Determination can occur any time after project is adopted as part of expansion plan
- CA ISO Need determined --> Application for CPCN and PEA (12 months)
- Application for CPCN is submitted --> Draft EIR (8-12 months)
- Draft EIR released --> Final EIR --> CPCN issued (8 months)
- CPCN issued --> Construction (12-16 months)

The process described in Table 4 allows for consideration of alternatives primarily at in Step 1, in which the IOU and the CA ISO study group consider alternatives to solving an identified problem that do not require construction of new transmission. These solutions can involve substation improvements and transmission line reconductoring. If these solutions have already been implemented or are not feasible, the result of Step 1 is generally the proposal of a new transmission line.

In Steps 2-3 when the IOU is evaluating specific methods to solve an identified problem, there is still flexibility for consideration of non-transmission options, but the planning focus is on transmission line routing, generally between two identified substations.

A detailed alternatives analysis is prepared in Step 5 in the CEQA process. However, at this point the problem has usually become urgent enough that longer-term solutions are not considered to be feasible. Timing alone can eliminate alternatives that require more lead-time to implement.

Role of the California Independent System Operator

The California Independent System Operator (CA ISO) is the umbrella agency that controls 75 percent of California's power grid, transmission systems formerly operated by the three IOUs, covering 124,000 square miles (CA ISO, 2004a). To aid in control of the grid, the CA ISO regularly develops a forecasted mix of loads, resources, and transmission capacity in the CA ISO Control Area for near-term seasons. The CA ISO also collaborates with state, federal, and other agencies to help California plan to meet future electricity needs and to avoid future shortages such as those that the state experienced in 2001.

On October 10, 2003, the CA ISO published a long-term assessment of electricity needs in the CA ISO Control Area, which provides a baseline forecast of CA ISO electricity needs and evaluates potentially adverse conditions, and additional risks and sensitivities. This Five-Year Assessment provides valuable input for the CA ISO's contribution in a variety of reliability-related forums concerning operations, grid planning, and transmission maintenance. The CA ISO conducts an annual Coordinated Grid Planning Process with the CA ISO's participating transmission owners [i.e., IOUs including Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), discussed below] and uses planning information from the individual IOUs towards its system-wide Controlled Grid Study, which is also described below. The CA ISO also contributes to the Seams Steering Group-Western Interconnection (SSG-WI), planning towards a seamless regional transmission system and supports the development of a statewide resource adequacy policy to assure that a sufficient supply of electricity (generation and import commitments) and transmission is in place to continually meet all electricity demands.

The CA ISO has provided recommendations to the CPUC for developing a formal long-term and short-term electric resource (generation, transmission, and demand-side) planning and procurement process (CPUC Proceeding No. R.01-10-024). The CA ISO has also provided input to the Energy Commission's IEPR proceeding, which identifies historic and current energy trends, forecasts and analyzes potential future energy developments, and recommends new policies for current and pressing energy issues facing the state.

The following sections describe the CA ISO's operational requirements and constraints, and the various CA ISO planning processes, including IOUs annual transmission expansion plans. Other CA ISO programs are described in the Appendix: CA ISO Controlled Grid Studies, the Southwest Transmission Expansion Plan (STEP), RMR processes, and Transmission Economic Assessment Methodology (TEAM).

Operational Requirements and Constraints of the CA ISO

The CA ISO's operational requirements can trigger projects that result in expansion of the transmission grid.

Operation of the grid must meet national and regional reliability standards. To comply with the reliability standards, grid operators routinely assess performance of the system to ensure reliable performance. When potential reliability problems are identified, the CA ISO and the transmission owners investigate strategies for improving the system. The strategies can include expansion of the system or changes in system operation. If CA ISO determines that expansion of the system is the preferred alternative, then the transmission owner would be obligated to initiate the project (CA ISO Tariff §3.2.1.2).

Expansion of the transmission grid may also be economically-driven (CA ISO Tariff §3.2.1.1). Grid operators normally identify areas of congestion and penalize the transmission owners for the diminished efficiency of the grid by requiring congestion fees. Where cumulative congestion costs reach a certain threshold, economically-driven transmission expansion may be triggered. Some grid operators (e.g., Pennsylvania-New Jersey-Maryland Interconnection (PJM)) define a threshold for determining the need for economically-driven projects. On the CA ISO grid, economic expansions may be initiated by the transmission owners or other parties voluntarily, without CA ISO involvement. If the transmission owner demonstrates the financial capability to construct an economically-driven project, then the need for the project would be sufficiently demonstrated to the CA ISO (CA ISO Tariff §3.2.1.1.2). In this way, the CA ISO congestion costs can trigger grid expansion projects.

Investor-Owned Utilities' Annual Transmission Expansion Plans

Regulatory Background. California's participating transmission owners (including IOUs) are required by CA ISO to file annual transmission expansion plans (CA ISO Tariff §3.2.2.1). The plans must show how the transmission owners (e.g., IOUs) will meet all CA ISO reliability criteria for a minimum planning horizon of five years. As transmission utilities, it is the obligation of the transmission owners, in coordination with CA ISO, to determine what type of facilities would need to be constructed to meet the CA ISO reliability criteria (CA ISO Tariff §3.2.3).

The CA ISO Tariff approved by the FERC dictates how CA ISO treats expansion of the transmission system. The CA ISO tariff requires that each participating transmission owner construct all the upgrades needed to ensure reliability. However, the obligation to construct additions and upgrades is subject to the owner's good-faith ability to obtain all necessary approvals and property rights and the presence of a cost recovery mechanism for the owner (CA ISO Tariff §3.2). When the CA ISO makes a determination that upgrades are needed to maintain system reliability, it must consider lower-cost alternatives including expanded use of existing facilities, DSM, peaking generation, or interruptible loads (CA ISO Tariff §3.2.1.2).

The need for an economically driven transmission upgrade can also be initiated by the transmission owner. If requested by the owner or another party, the CA ISO may determine whether the upgrade will improve economic efficiency according to a variety of criteria (CA ISO Tariff §3.2.1.1).

Once the CA ISO determines the need for a transmission addition or upgrade, the cost of the upgrade must be borne by the transmission owner (CA ISO Tariff §3.2.7.2). If the owner cannot secure the necessary approvals or property rights and is therefore unable to construct a transmission addition or upgrade, the CA ISO must take actions with the owner and other stakeholders to facilitate development and evaluation of alternative proposals (CA ISO Tariff §3.2.5.2).

The CA ISO is not a Regional Transmission Organization (RTO),[1] and as such CA ISO is not currently required to have a formal regional transmission planning process. Although CA ISO currently requires system owners to file expansion plans and requires the owners to develop needed expansions, CA ISO's current planning process is not codified. The FERC rulemaking that is currently in progress would eventually require CA ISO to establish a formal planning process. The federal proposal for Standard Market Design would require an independent assessment of the transmission facilities needed by the region, balancing participation of state commissions, transmission owners, and other market participants. If the FERC's current proposal is finalized, CA ISO would also be required to establish a cost recovery mechanism for regional transmission expansions (FERC, 2003).

[1] Regional Transmission Organizations are transmission system operators meeting the criteria of FERC Order 2000.

Description of Process. The IOUs file annual transmission expansion plans to accommodate the state's growing electricity needs. These plans typically focus on a five-year horizon highlighting reliability needs and responding to load growth. IOUs, also known as private utilities, are owned by stockholders, governed by a private board, and regulated by the CPUC. The three main IOUs in California are PG&E in the northern and central parts of the state, SCE in central and southern California, and SDG&E in San Diego and southern Orange Counties.

The present coordinated planning process relies heavily on annual transmission plans filed by the IOUs and all other participating transmission owners for the portions of the grid that they own. The CA ISO reviews and either approves or make recommendations regarding the proposed additions. Recommendations that are not accepted go to a dispute resolution process. As part of a coordinated planning process, the CA ISO works with regional transmission groups, primarily through the Western Electricity Coordinating Council (WECC), to ensure that expansion projects do not negatively impact the regional grid and transmission owners in other states.

These annual plans are coordinated with neighboring systems and describe proposed facility additions over a minimum five-year planning horizon. Plans identify system concerns and evaluate the technical merits of various potential transmission, generation, and operating alternatives. In conducting their analyses and developing preferred alternatives, the IOUs are required to address the needs identified by the various market participants (CA ISO, 2001). The various power flow and stability base cases developed for these annual plans are then used by the CA ISO and other market participants for integrated review and independent studies.

The goals of the various projects developed through this coordinated process and within the individual IOU's annual Expansion Plans include the following: interconnecting generation or load; protecting or enhancing system reliability; improving system efficiency; enhancing operating flexibility; reducing or eliminating congestion; and minimizing the need for RMR contracts (CA ISO, 2001).

Major Participants in the Process and Pending Projects

Pacific Gas and Electric Company (PG&E). PG&E owns 57 percent of the state's 33,000 miles of power lines. As a part of the CA ISO Grid Planning Process, PG&E conducts a system assessment of its transmission facilities and develops an Annual Electric Transmission Grid Expansion Plan for the PG&E territory that focuses, among other things, on specific projects for the first five years, conceptual projects for the second five years and beyond, results and recommendations from previous CA ISO Controlled Grid Studies, RMR cost reduction, and coordination with market participants. The draft of PG&E's 2004 Electric Transmission Grid Expansion Plan is expected to be published on August 31, 2004 and it is expected to be finalized in November 2004. Currently there are numerous transmission and generation interconnection projects before the CPUC and under construction to increase system reliability.

Under Assembly Bill (AB) 970, PG&E and all IOUs are required to submit Monthly Compliance Reports to the CPUC as a means to identify electric transmission and distribution constraints, present actions to resolve those constraints, and discuss related matters affecting the reliability of electric supply. The following projects are included in PG&E's April 2004 Monthly Compliance Report:

- The Jefferson-Martin 230 kV Transmission Line Project, which involves construction of a new 27-mile long 230 kV partially overhead/underground line between Jefferson and Martin Substations in San Mateo County, has a pending CPCN.
- Eight projects with effective Notices of Construction (NOC) are under construction, and there are 14 projects in planning that will require an NOC. These projects mainly consist of reconductoring and looping in power lines to the system.
- Three projects with effective Permits to Construct (PTC) that are under construction and one in planning that will require a PTC. These projects primarily consist of upgrades and construction of new power lines under 200 kV to increase supply.
- Six projects are in planning and the CPUC has yet to determine whether a PTC, NOC, or CPCN will be required. These projects include reconductoring and the construction/installation of new power lines.
- There are 51 projects that are exempt from CPUC approval, consisting mainly of rerates and installation of new equipment at existing facilities.

Southern California Edison (SCE). SCE owns 16 percent of the state's transmission lines. SCE's annual transmission planning is similar to PG&E's process described above. Like PG&E and SDG&E, SCE publishes a Transmission Grid Expansion Plan for increasing reliability in the SCE territory and informing the CA ISO Coordinated Grid Planning Process. Currently there are numerous transmission and generation interconnection projects before the CPUC and under construction to increase system reliability, including the following contained in SCE's April 2004 Monthly Compliance Report:

- The Tehachapi Transmission Line Project, a new 230 kV transmission line to connect approximately 800 MW of new wind generation, is in the planning stages, does not yet have CA ISO approval, and will most likely require a CPCN.
- The Viejo 230 kV/66 kV Substation Project will loop the San Onofre-Chino 230 kV lines into a new Viejo Substation to serve loads in southern Orange County and is currently in the environmental review process under an application for a PTC.
- The reconductoring of the Pardee-Pastoria 230 kV transmission line does not yet have CA ISO approval. The project will require approval from the United States Forest Service in addition to the CPUC.
- Twelve projects are exempt from CPUC approval, consisting mainly of re-rates and installation of new equipment at existing facilities.

In addition there are two projects that SCE plans to construct but are not listed on the Monthly Compliance Report. Applications have not yet been filed with the CPUC for these projects:

- The Devers-Palo Verde #2 Project, requiring a CPCN, would include the construction of a second 500 kV transmission line along the existing right-of-way (ROW) between SCE's Devers Substation near Palm Springs and the Palo Verde Generating Station switchyard west of Phoenix, Arizona. This project would facilitate the delivery of new merchant generation in the Palo Verde and Blythe areas west into California.
- The Stagecoach Project would include the construction of a new "Stagecoach" 500/230 kV substation needed to service rapidly growing power demand in western San Bernardino County (SCE, 2004).

San Diego Gas and Electric (SDG&E). With six percent of California's power lines, SDG&E's annual transmission planning is similar to PG&E's and SCE's processes described above. SDG&E publishes a Transmission Grid Expansion Plan for increasing reliability in the SDG&E territory and informing the CA ISO Coordinated Grid Planning Process. Currently there are numerous transmission and generation interconnection projects before the CPUC and under construction to increase system reliability, including the following contained in SDG&E's April 2004 Monthly Compliance Report:

- The Miguel-Mission 230 kV #2 Project in San Diego County is currently under environmental review for its CPCN application. A proposed decision on this 35-mile 230 kV transmission line in SDG&E's existing ROW is expected soon after June 2004.
- SDG&E has filed an application for a CPCN for the Otay Mesa Power Purchase Agreement Transmission Project, proposing a new 230 kV line from Miguel to Old Town and Miguel to Sycamore Substations.
- Two separate PTCs have been filed for the construction of new Mira Sorrento and Uptown Substations and two more for the Orange County and Discovery Valley Substations, are expected later in 2004.
- There are 29 exempt projects, which consist mainly of rerates and installation of new equipment at existing facilities.

Processes for Evaluation of Alternatives

Alternative solutions for transmission system improvements must simultaneously satisfy reliability criteria, economic goals, and environmental standards. Currently, consideration of these issues depends drastically on the participants and forum.

Project proponents and transmission system operators can work together to identify whether non-transmission alternatives are available for avoiding additions or expansions to the transmission system. Comparisons of options can take place at any time during system planning or development of a specific project, but is most useful at early planning stages.

- **Reliability Criteria:** Solutions to improving the transmission system must generally meet the reliability criteria of the CA ISO Grid Planning Standards or criteria from North American Electric Reliability Council (NERC)/WECC. Non-transmission alternatives may be identified by stakeholders or other parties participating in the planning process of the transmission system operator, and the grid operator, normally in conjunction with WECC, may determine whether the alternatives satisfy the reliability criteria.
- **Economic Goals**: The economic interests of market participants may also be considered during the process of comparing alternatives. For example, non-transmission alternatives such as demand management may be economically beneficial to power customers reducing their demand, but may not be beneficial to generators of power that depend on power sales for revenue.
- **Environmental Standards:** Any solution for improving transmission system reliability or market economics would need to comply with a wide range of environmental standards if it would result in any physical change to the environment. Land use approvals and environmental permits may need to be obtained, and, depending what type of agency action is necessary for an alternative, the CEQA and/or the National Environmental Policy Act (NEPA) process may apply. These comprehensive environmental acts require a comparison of the environmental consequences of each alternative. Agencies administering CEQA or NEPA are free to identify non-transmission alternatives if they may be environmentally superior to a proposed transmission expansion.

Assessment of Alternatives Under CEQA

The California Environmental Quality Act (CEQA) was adopted in 1970 and applies to projects undertaken, funded or that require an issuance of a permit by a public agency, such as the Energy Commission. The purpose of CEQA is to inform governmental decision-makers and the public about potential environmental effects of a project; identify ways to reduce adverse impacts; offer alternatives to the project; and disclose to the public why a project was approved. The Energy Commission conducts a review for power facility sites that is equivalent to CEQA under the Warren-Alquist Act.

One of the most important aspects of the environmental review process is the identification and assessment of reasonable alternatives that have the potential for avoiding or minimizing the impacts of a proposed project. In addition to mandating consideration of the No Project Alternative, CEQA Guidelines (Section 15126(d)) emphasize the selection of a reasonable range of feasible alternatives and adequate assessment of these alternatives to allow for a comparative analysis for consideration by decision makers. An Environmental Impact Report (EIR) should explain why other alternatives have been eliminated from evaluation and provide a meaningful evaluation, analysis, and comparison of alternatives' impacts to those of the Proposed Project, and identify the environmentally superior alternative. If necessary, an EIR may also evaluate alternative project locations if the project is proposed by a public agency, the developer owns, controls, can buy, or has access to other sites, or two developers are seeking approval for the same project type at different sites. CEQA Guidelines (Section 15126(a)) state that

> *An EIR shall describe a reasonable range of alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project*

CEQA requires that each significant impact of a project be identified in the EIR and feasible mitigation measures or alternatives be identified and implemented. This is the primary place in the project planning process where alternatives are carefully considered, evaluated, and may be approved and implemented.

In order to comply with CEQA's requirements, each alternative suggested or developed for a project is evaluated in three ways:

1. Does the alternative allow meeting of most basic project objectives?
2. Is the alternative feasible (does it meet legal, regulatory, technical requirements)?
3. Does the alternative avoid or substantially lessen any significant effects of the Proposed Project (including consideration of whether the alternative itself could create significant effects potentially greater than those of the Proposed Project)?

These three factors are described in greater detail below.

- **Consistency with Project Objectives.** CEQA Guidelines require the consideration of alternatives capable of eliminating or reducing significant environmental effects even though they may "impede to some degree the attainment of project objectives" (Section 16126.6(b)). Therefore, it is not required that each alternative meet all of the applicant's objectives.

  Although the Lead Agency should not describe the alternatives so narrowly as to preclude any alternatives, one court has found an EIR that contained only one alternative (other than the No Project Alternative) to be adequate because of the very explicit and narrow project objective [*Marin Municipal Water District v. K.G. Land Corporation* (1991) 235 Cal. App. 3d 1652]. On the other hand, if the project has multiple objectives, every alternative need not satisfy every objective. It is sufficient if each alternative meets most of the project's objectives [*City of Carmel-by-the-Sea v. United States Department of Transportation* (9th Cir. 1997) 123 Fed. 3d 1142].

- **Feasibility.** CEQA Guidelines (Section 15364) define feasibility as ". . . capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors." In addition, CEQA requires that the Lead Agency consider site suitability, economic viability, availability of infrastructure, general plan consistency, other regulatory limitations, jurisdictional boundaries, and proponent's control over alternative sites in determining the range of alternatives to be evaluated in the EIR (CEQA Guidelines Section 15126.6(f)). Generally for an alternatives screening analysis, the feasibility of potential alternatives is assessed with respect to its ability to meet legal, technical, and regulatory requirements. The assessment is directed toward reverse reason, that is, a determination is made as to whether there is anything about the alternative that would be infeasible on technical or regulatory grounds. These alternatives screening analyses do not focus on relative economic factors or costs of the alternatives (as long as they are found to be economically feasible) since CEQA Guidelines require consideration of alternatives capable of eliminating or reducing significant environmental effects even though they may "impede to some degree the attainment of project objectives or would be more costly" (Guidelines Section 16126.6(b)).

- **Potential to Eliminate Significant Environmental Effects**. A key CEQA requirement for an alternative is that it must have the potential to "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 16126.6(a)). If an alternative is identified that clearly does not provide potential overall environmental advantage as compared to the proposed project, it may be eliminated from further consideration. In some cases, an alternative may eliminate a proposed project effect, but it may create a new significant effect in a different discipline or geographic area. In these cases, the aggregate environmental effects of the proposed project segment or site and the alternative segment or site need to be compared to determine whether the alternative meets the overall CEQA requirement. At the alternatives screening stage, it is not possible to evaluate all of the impacts of the alternatives in comparison to the proposed project with absolute certainty, nor is it possible to quantify impacts. However, it is possible to identify elements of an alternative that are likely to be the sources of impact and to relate them, to the extent possible, to general conditions in the subject area in order to make a determination of whether to retain the alternative for full evaluation.

No Project Alternative. CEQA requires an evaluation of the No Project Alternative in order that decision makers can compare the impacts of approving the project with the impacts of not approving the project. According to CEQA Guidelines [Section 15126.6(e)], the No Project Alternative must include (a) the assumption that conditions at the time of the Notice of Preparation (i.e., baseline environmental conditions) would not be changed since the Proposed Project would not be installed, and (b) the events or actions that would be reasonably expected to occur in the foreseeable future if the project were not approved. The first condition is generally described in an EIR for each environmental discipline as the "environmental baseline," since no impacts of the proposed project would be created. The EIR also defines the second condition, reasonably foreseeable actions or events, and each issue area evaluates the impacts of these actions.

Rationale for Rejecting Alternatives. As discussed above, the Lead Agency may, as part of the scoping and/or screening process, make an initial determination as to which alternatives are feasible and merit in-depth consideration and which do not. Although an EIR should generally set forth the alternatives that the Lead Agency considered and rejected as infeasible during the scoping process and the reasons for their rejection, such explanations may be found elsewhere in the administrative record. Thus the entire administrative record, and not merely the EIR, may be studied to assess the degree of discussion any particular alternative deserves based on its feasibility and the stage in the decision-making process at which it is brought to the attention of the Lead Agency. Alternatives that are brought to the Lead Agency's attention after the public review period must also be considered, but the Lead Agency may address these alternatives by means of administrative findings, rather than in a Supplemental EIR [*Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal. App. 3d 553].

Alternatives that are remote or speculative, or the effects of which cannot be reasonably predicted, need not be considered. However, alternatives may not be rejected merely because they are beyond an agency's authority, would require new implementing legislation, or would be too costly [Section 15126(f)(2)].

An EIR should analyze alternatives even if mitigation measures can reduce impacts of the proposed project to less than significant levels. If it concludes that no feasible alternatives exist, an EIR must present the reasons why alternatives were rejected in sufficient detail to enable meaningful public review. The Lead Agency's responsibility to provide an adequate analysis of alternatives does not depend on project opponents first showing that feasible alternatives exist (Bass et al., 1999).

Comparing NEPA and CEQA. Compliance with NEPA is required for all projects that require approval by a federal agency (e.g., the Western Area Power Administration). Under NEPA, the proposed project and a range of alternatives to the project are all examined at the same level of detail (i.e., the proposed project is seen as one of several alternatives). NEPA requires an Environmental Impact Statement (EIS; similar to the CEQA Environmental Impact Report) to "devote substantial treatment to each alternative considered in detail." Similar to CEQA's No Project Alternative, NEPA requires the analysis of a "No Action" Alternative. CEQA, however, does not require alternatives to be examined in as great a detail as the proposed project (i.e., alternatives are means of avoiding the impacts associated with the project). In addition, under CEQA, consideration of project need is not explicitly required as it is in NEPA.

CEQA's requirement that an EIR must consider a "range of reasonable alternatives" that achieve the objectives of the project, in "meaningful detail" has been interpreted as less onerous than NEPA's "substantial treatment" standard. The NEPA process may lead to better planning through the environmental review process, but it also can result in long, cumbersome environmental documents. In addition, NEPA requires, as part of the discussion of each alternative, discussion of mitigation measures and growth inducing impacts. CEQA requires a separate discussion of these issues, focusing on the proposed project.

Assessment of Alternatives Under the Energy Commission Siting Process

The Energy Commission conducts a review for power facility sites that is equivalent to CEQA under the Warren-Alquist Act.

New power producing facilities that are subject to the Energy Commission's licensing process must undergo an assessment of alternatives to the proposed projects. The process of alternatives assessment is equivalent to that required under CEQA, and before the project proponent or applicant can receive a favorable decision from the Energy Commission, the Commission must find that there is no feasible alternative that would accomplish project objectives with fewer environmental impacts.

Energy Commission staff conducts the review of optional locations for the proposed facility and a review of alternative technologies. The analysis takes into account the availability of alternative energy resources (such as use of renewable power sources) and alternative power plant designs. In recent cases, Energy Commission staff has recommended changes to the water supplies or the power plant cooling systems originally proposed by applicants to minimize impacts on water resources. In every case, the analysis must review whether there would be any alternatives to reduce wasteful, inefficient and unnecessary energy consumption. The analysis must also consider whether or not interconnection of the power plant to the grid would adversely affect surrounding transmission systems. This analysis occurs with consultation and review from CA ISO.

The analyses conducted by the Energy Commission normally consider expanding transmission as a possible option to new power producing facilities, although project applicants usually state power production as a common project objective and the lead-time to design and construct expansions to transmission facilities usually exceeds the lead-time to construct a proposed power plant.

In certain cases, viable transmission alternatives may exist, and they are reviewed as necessary. Transmission alternatives were reviewed closely in the staff assessment for the Potrero Power Plant Unit 7 Project in San Francisco. The following conclusion was made in the Final Staff Assessment (Docket 00-AFC-4, February 13, 2003):

> *Therefore, transmission is not considered to be an alternative to generation for four reasons: (1) transmission does not meet project objectives (it provides less reliability benefit and would not be operational within the same timeframe as the proposed project); (2) the significant local system benefits [from locating the power plant in San Francisco] demonstrated in the Local Systems Effects section of this FSA would not be attained; (3) the transmission improvements on the San*

Francisco peninsula currently in the planning process are expected to be completed regardless of the approval of the Potrero Unit 7 project; and (4) feasibility of the Moraga-Potrero (cross-bay) transmission line is doubtful and it could very well entail much higher environmental consequences.

CPUC Alternatives Analyses for Specific Transmission Projects

This section describes the history of alternatives considered in individual transmission project proceedings completed by the CPUC in compliance with CEQA over the past 10 years. Under each project, the proposed project is described and alternatives that were considered are summarized. Staff also talked to members of the public who have been actively involved in transmission projects to get their feedback for this analysis.

Alturas Transmission Line EIR/S Project

CPCN Application 1993; Approval 1996

Proposed Project. This project, proposed by Sierra Pacific Power Company (SPPCo), consisted of construction and operation of a 164-mile 345 kV overhead transmission line from the vicinity of Alturas, California to Reno, Nevada. Key issues included biological and archaeological resources, human health effects of EMF, visual resources and aesthetics, land use, geology, and hydrology. An extensive analysis of the need for the transmission line was also conducted. Significant impacts that could not be reduced to less than significant levels with mitigation were found in the following issue areas cultural resources, geology, soils, and paleontology, land use and recreation, traffic and transportation, and visual resources.

Alternatives Evaluated. Eight overhead alternative route alignments and two alternative substation sites were chosen for detailed analysis in the EIR/S, as well as the No Project Alternative/Action.

Alternatives Eliminated From Full Consideration. The alternatives considered but not fully evaluated included several transmission system alternatives through Nevada, many variations on the proposed route (totaling over 90 miles), undergrounding the line, and alternative technologies (generation and system enhancements). The generation alternatives that were eliminated from full consideration were the construction of the Piñon Pine Power Plant, siting studies for the Fort Churchill Combustion Turbine, and use of geothermal and solar energy technologies. The system enhancement alternatives included demand side measures, and installation of a Static Var Compensator or capacitor banks.

PG&E Northeast San Jose Transmission Reinforcement Project

CPCN Application 1998; Approval 2001

Proposed Project. This proposed project consisted of construction and operation of a 7.3-mile long 230 kV double-circuit transmission line from an existing substation in the City of Fremont to the proposed new 24-acre 230 kV substation in unincorporated Santa Clara County. The proposed project would have required construction of a major transmission line on the eastern edge of the San Francisco Bay, adjacent to the Don Edwards San Francisco Bay National Wildlife Refuge (Refuge) and to a series of wildlife and open space preservation areas. Specific concerns with the proposed project focus on its potential for significant visual impacts, degradation of recreational experiences along the Bay margin trails, and the potential for bird collision with the transmission conductors.

Alternatives Evaluated. Ten alternatives were analyzed in the Draft EIR, including five 230 kV transmission line route alternatives, two substation site alternatives, two alternatives to the 115 kV portion of the project, and the No Project Alternative. Six new or revised alternatives were analyzed in the Supplemental Draft EIR, including five potential modifications to the 230kV transmission line route and one new substation site alternative.

Alternatives Eliminated From Full Consideration. Twelve potential alternatives were eliminated from further consideration because they did not offer significant environmental advantages over the proposed project or because of engineering/feasible issues. System alternatives that were eliminated from full consideration included: the development of new local generation with 115kV upgrades, distributed generation/local generation, and upgrading existing 115kV lines and substations.

Los Banos–Gates 500kV (Path 15) Transmission Project

Application 2001; not approved

Proposed Project. The major elements of the proposed project included construction and operation of approximately 84 miles of 500 kV overhead transmission line between PG&E's Los Banos Substation in southern Fresno County and the Gates Substation in Fresno County near Coalinga. Concerns were related to the following issues: effects on agricultural lands and oil fields; biological impacts within the Western Corridor; visual degradation of the landscape; the negative effect on property values, and the potential loss of use of land between adjacent parallel transmission line corridors.

Alternatives Fully Evaluated. Five overhead transmission line alternatives, in addition to the No Project Alternative, were analyzed in the Draft Supplemental EIR. One alternative route that was 84 miles long was designed to connect the Los Banos and Gates Substations by following a path that is generally located on the east side of I-5 on the western fringe of the San Joaquin Valley. The other four overhead transmission line alternatives were shorter alternative route segments.

Alternatives Eliminated From Full Consideration. Three complete overhead 500 kV transmission line route alternatives were eliminated from further review because load growth studies did not support their consideration, excessive length of transmission lines would be required, and/or they would not include the use of existing system infrastructure. In addition, two overhead 500 kV route segment alternatives were eliminated from further review because the issues that led to the identification of the segments were resolved.

Tri-Valley 2002 Capacity Increase Project

CPCN Application 1999; Approved 2001

Proposed Project. PG&E's proposed project included construction and operation of 10.7 miles of new 230 kV overhead double-circuit transmission line in the Pleasanton, Dublin, and Livermore areas and 2.7 miles of 230 kV underground double-circuit transmission line to in the Pleasanton area, and construction of two new substations. The areas of controversy associated with the proposed project and alternatives were as follows: the potential for project construction and operation to affect residential areas, especially in the Cities of Pleasanton and Livermore; concerns related to EMF, visual impacts, construction impacts, and the use of relatively new solid dielectric cable technology at the 230 kV level; visual and land use impacts (particularly in the north and south Livermore areas); and the location of an alternative amidst commercial land uses.

Alternatives Fully Evaluated. The 13 alternatives that were fully evaluated in the project EIR were divided into four categories because of the geographic spread of this project: Pleasanton, Dublin/San Ramon, North Livermore, and Tesla Connection. The Draft EIR included analysis of four alternatives (including one local generation alternative) for the Pleasanton Area, two alternatives for the Dublin/San Ramon Area, three alternatives for the North Livermore Area, three alternatives to the Tesla Connection (Phase 2), as well as the No Project Alternative. In addition to these alternatives, the Draft EIR considered three modifications to alternatives that were designed to eliminate specific impacts.

Alternatives Eliminated From Full Consideration. Twenty-three potential alternatives were eliminated from further consideration because they did not offer significant environmental advantages over the proposed project or because of engineering/feasible issues. These alternatives included four underground routes, seven overhead routes, eight new substations, two transmission line reconductoring alternatives, one alternative that would serve Pleasanton through existing distribution lines, and one alternative that would utilize wind power.

PG&E Proposed Jefferson-Martin 230 kV Transmission Project

CPCN Application 2002; Decision expected mid-2004

Proposed Project. PG&E's proposed project was located on the San Francisco Peninsula, nearly entirely within San Mateo County. The proposed project includes construction and operation of 14.7 miles of 230 kV overhead line to be installed with an existing 60 kV double-circuit transmission line from 12.4 miles of new 230 kV underground duct bank. The majority of public concern focused on the potential effect of the project on the human environment, most often expressing concerns with health risks arising from increased EMF emissions, visual and scenic impacts, and impacts to property values. Other common concerns expressed dealt with safety issues, noise, construction impacts, fire risks, interference with communication and electronic equipment, security, conflicts with planned uses, recreation impacts, and quality of life.

Alternatives Fully Evaluated. Two complete alternative routes were fully evaluated, including an all-underground option that would be entirely within roadways, and a route that includes a combination of overhead and underground segments. Four underground route segment alternatives were also fully evaluated. The other three underground route segment alternatives would consist of short routes within city streets to avoid particular areas. In addition, five alternative transition station sites were fully evaluated.

Alternatives Eliminated From Full Consideration. Eighteen transmission line route alternatives were eliminated from further consideration. Several non-wires alternatives, including new generation alternatives, renewable resource alternatives, system enhancement alternatives, and integrated resource alternatives were also eliminated from further consideration. The non-wires alternatives that were eliminated from full consideration included:

- New Generation Alternatives (Potrero Unit 7, San Francisco Williams Turbines)
- Renewable Resource Alternatives (Solar, Wind, and Tidal Technologies)
- System Enhancement Alternatives (Distributed Generation and Demand-side Management)
- Integrated Resource Alternatives.

SDG&E Proposed Miguel-Mission 230 kV #2 Project

CPCN Application 2002; Decision expected mid-2004

Proposed Project. Construction and operation of three major transmission line components in San Diego County: (1) the installation of a new 230 kV circuit on modified steel lattice structures; (2) relocation of the existing 138 kV and 69 kV circuits onto a new alignment of poles within the existing Miguel-Mission ROW; and (3) modification of the Miguel and Mission Substations to accommodate the new 230 kV circuit. Public comments expressed concern that the applicant had not provided: (1) adequate justification for project need; (2) an adequate description of future use for the transmission line; (3) an adequate description of future growth in the area and impact on energy supply and demand; (4) information on energy sources and markets; and (5) a sufficiently detailed explanation on what is causing the demand for the Proposed Project.

Alternatives Fully Evaluated. Two transmission line underground alternatives and three overhead transmission line alternatives were fully evaluated.

Alternatives Eliminated From Full Consideration. Eleven transmission routing alternatives, including alternatives west and south of Miguel Substation, were found to meet project objectives, but there were feasibility concerns with several, and most would have greater environmental impacts than the Proposed Project; therefore, they were eliminated from full consideration in the EIR. Several non-wires alternatives were also eliminated from further consideration, including: Renewable Resource Alternatives (Wind and Solar Technologies); System Enhancement Alternatives (Demand-Side Management and Distributed Generation); and Integrated Resources Alternatives.

SDG&E Valley-Rainbow 500 kV Interconnect Project

CPCN Application 2001; application rejected 2002

Proposed Project. The Valley-Rainbow 500 kV Interconnect Project consists of the following new or expanded electric transmission and substation facilities. A single circuit 500 kV electric transmission line approximately 31 miles in length would connect a proposed new SDG&E 500 kV/230 kV bulk power transmission substation near the community of Rainbow in San Diego County to SCE's Valley substation near Romoland in western Riverside County. The proposed 500 kV transmission line would be built on steel poles and lattice towers within a new ROW.

Most of the concerns that were raised in the scoping process involved environmental issues and concerns, growth inducement, purpose and need for the project and alternatives. Possible impacts to quality of life, property values, visual and aesthetic qualities of the area, wine making and other agricultural operations, placement of schools and parks, community and residential development, recreation (including hot air ballooning), and human health were addressed by the public as well.

In addition to these concerns, the U.S. Bureau of Land Management (BLM, the federal lead agency for NEPA compliance) identified issues related to wildlife, including threatened and endangered species, cultural resources, and Native American concerns. U.S. Rep. Darrell Issa introduced legislation in September 2002 to combine two power lines into one route and create a transmission corridor through the Cleveland National Forest in Riverside County to avoid impacts to the Temecula Valley and Pechanga Indian Reservation. The bill, HR 5409, identified a path to the west that would traverse the eastern edge of the Trabuco District of the Cleveland National Forest. This route was viewed as a compromise solution because it protects the interests of the Pechanga Tribe and residents of the Temecula Valley, while providing for a transmission corridor on federal land to guarantee reliable delivery of power to consumers. Currently Cleveland National Forest is concerned about visual and biological resources impacts of a line through its jurisdiction the forest, which is already on the California Wilderness Coalition’s “Ten Most Threatened Wildlands” list.

CPUC Action. On October 21, 2002, ALJ Michelle Cooke directed the Energy Division of the CPUC to prepare and file within 30 days of the ruling a document that provided a preliminary alternatives feasibility analysis based on the environmental information that had been developed to date. The Interim Preliminary Report on Alternatives Screening was published on November 21, 2002.

On December 19, 2002, the CPUC rejected SDG&E's application (D.02-12-066, rehearing denied in D.03-05-038) based on need and cost-benefit analysis (CPUC, 2002). The Commission denied the CPCN despite the fact that the California CA ISO had approved the project and directed SDG&E to construct the line in order to satisfy a need it had identified. CA ISO provided a witness to testify to that effect in the hearing. Nonetheless the CPUC disagreed and found that need had not been demonstrated. Preparation of the EIR/S ceased.

Alternatives Screening Process. In total, the alternatives screening process resulted in the identification and screening of approximately 45 alternatives. These alternatives ranged from minor routing adjustments of SDG&E's proposed 500 kV project location to alternative system voltages, system designs, and routing options that were under consideration in other parts of San Diego, Riverside, Orange and Imperial Counties, as well as non-wires alternatives. Routing alternatives were evaluated for the 500 kV transmission line and Rainbow substation portions of the proposed project.

EXAMPLES OF TRANSMISSION ALTERNATIVES

This section begins consideration of possible procedural changes for California by studying two actual examples of alternatives to transmission: the CA ISO's January 2000 Request for Proposals (RFP) for peaking power in the Tri-Valley area and the ongoing efforts of the Bonneville Power Administration (BPA) and its non-wires initiative working group.

2001 CA ISO RFP Process for the Tri-Valley Area

On January 8, 2000, CA ISO initiated a RFP as a pilot effort in its evolving grid planning process (CA ISO, 2000). Specifically, in the course of preparing its annual transmission expansion plan, PG&E had identified a number of future transmission projects that, if not replaced by non-wires alternatives, would be needed for local reliability purposes. At this time, PG&E delivered electric power to its customers in the southern Tri-Valley area using four 60 kV transmission lines through PG&E's Radum, Vineyard and Livermore substations and several customer-owned substations. One such project was located in the southern Tri-Valley area of PG&E's Service Area. The CA ISO Governing Board approved PG&E's 230 kV transmission project at its January 27, 2000 Board meeting, subject to the outcome of the Tri-Valley RFP.

The energy need for this area was limited to peak periods during the warm months and was expected to occur for only a small percentage of hours each year. As an alternative to PG&E's identified transmission expansion project, the CA ISO sought proposals from Qualified Resources capable of providing peaking capability from generation to be installed in the southern Tri-Valley area and/or peak load management service from southern Tri-Valley area load management projects. This RFP was not a solicitation for RMR generation or local area reliability service (LARS). Rather, the CA ISO wanted to determine whether otherwise competitive (i.e., cost-effective and reliable) generation would agree to locate in the southern Tri-Valley area and provide peaking capability, and/or whether demand reduction could be encouraged through peak load management programs.

The peaking capability and the peak load management service sought through the RFP was required to be available for the CA ISO's call up to 500 hours per year during specified peak hours and peak periods of calendar years 2001 through 2005. CA ISO calls would be for a minimum period of 4 hours. The CA ISO sought call rights for approximately 175 MW of such service. In response to the RFP, respondents could offer such capability or service in quantities of from one to 49 MW per Qualified Resource, in increments of one MW.

Outcome and Conclusions of the RFP. On March 20, 2000, four entities submitted responses to the RFP proposing the following projects:

- Two project options at different sites where each project would be primarily combustion turbine but would also include integrated photovoltaic (up to 200 kW) [Option 1 was 49 MW and Option 2 was 91 MW (a 49-MW facility plus a 42-MW facility)].
- Combustion turbines that would generate 85 MW (42.5 MW at two sites).
- Load management in prescribed, cumulative power blocks by starting up gas-fired generation (5 MW by the Availability Date of April 1, 2001, 15 MW by April 2002, and 30 MW by April 2003).
- Simple cycle gas turbine and transmission system enhancements (44 MW on line in 2001 and 88 MW on line by 2003).

The four proposals offered a total of 220 MW of generation and 5 MW of load management programs starting in 2001. The proposals also included an additional 44 MW of generation available in 2003, and 15 MW of load management available in 2002 and 30 MW in 2003.

At the conclusion of the process, although the CA ISO Grid Reliability/Operations Committee found that the four proposals were reliable alternatives to the PG&E transmission project, but it did not believe that they represented cost-effective alternatives. Therefore, on April 18, 2000, the Grid Reliability/Operations Committee recommended that the CA ISO Governing Board direct the President and Chief Executive Officer to inform PG&E that it should proceed with the development and construction of the PG&E Tri-Valley Transmission Expansion Project, as approved by the CA ISO Governing Board at its January 27, 2000 meeting.

The PG&E Tri-Valley Capacity Increase Project was ultimately approved by the CPUC (Decision D.01-10-029) on October 10, 2001, and construction began in September 2002. The first two phases are operational; Phase 3 construction will begin in the summer of 2004.

Bonneville Power Administration (BPA)

The Bonneville Power Administration controls roughly 80 percent of the grid assets in the Pacific Northwest. BPA is not a public utility under the Federal Power Act, and it is not specifically subject to FERC orders related to market restructuring. BPA has voluntarily participated in past efforts to form an RTO in the region (dubbed previously RTO West, or Grid West as of March 2004), but the RTO is not yet established.

The Transmission Business Line of the Bonneville Power Administration is responsible for providing firm transmission service over the Pacific Northwest grid. The BPA Open Access Transmission Tariff (effective October 1, 2001) requires BPA to use due diligence to add necessary facilities or upgrade its system within a reasonable time, if needed to meet the demands of eligible customers (BPA Tariff §19.6). The tariff describes the procedures if BPA experiences delays or is unable to complete the needed new transmission facilities (BPA Tariff §20.1). In these circumstances, BPA is required to convene a technical meeting (similar to that required by the WAPA and CA ISO tariff) to evaluate what alternatives may be available to the customer. If BPA cannot identify reasonable alternatives, and the customer believes one exists, then the dispute may be referred to the FERC for resolution (BPA Tariff §20.2).

BPA is not required by the FERC to maintain a formal or routine transmission planning and expansion process, but it does conduct occasional planning studies. To address the region's transmission needs, BPA developed a transmission infrastructure program in 2001 that focused on maintaining reliable transmission service to population centers and evaluating and investing in non-construction (or non-wires) alternatives to transmission expansions. Certain major transmission expansion projects were found to be necessary, and progress on these projects continues through 2004.

Expanding Regional Planning. Improvements were also recommended to improve the region-wide perspective of BPA's transmission planning process. Planning could be expanded to a two-tier sequence, where first, a regional long-term (10-year) view would be provided by the Transmission Business Line to allow market participants sufficient time to develop competitive alternatives for future transmission system needs, then second, a project-specific process (5-year) would allow detailed comparisons of the alternative solutions proposed by the market participants. The elements of the recommendations for expanding the planning process were:

1. *The production of a biennial system-wide report that describes the expected use of BPA's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate BPA's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as building new generation in certain locations.*

2. *The refinement and implementation of the [BPA] Transmission Business Line's existing planning process to screen specific proposed transmission projects against the costs of various forms of suitably located and operated generation, load management, and transmission pricing (BPA, 2001).*

More specific process changes were recommended for bringing regional decision makers together early in the planning process, especially to investigate non-transmission options and to educate the parties about the ramifications of uncoordinated actions on the cost of delivered power. The steps recommended for the revised planning process were:

1. *Produce a long-term transmission plan showing expected congestion points and the differential costs of delivering power to various points on the grid. With this,*

characterize the possible range of changes to transmission rates that could be needed to address those costs.

2. *Conduct a scoping workshop with interested parties to display and discuss the results of Step 1. Gather potential development plans identified by other parties for incorporation into the long-term plan.*

3. *Solicit analysis of the workshop and consultation for alternative cost-effective and reliable non-wires actions that parties could take individually and collectively.*

4. *Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction to alleviate the problems identified in the initial long-term plan. Identify uncertainties of acquisition and reliability in operation of any proposed alternatives to wires and uncertainties of their cost effectiveness (e.g., because of unpredictable fuel prices, load growth, regulatory conditions, or market structure).*

5. *Options for completing the region-wide planning process could include:*

   a. *Concluding that there are no economic and reliable options to wires, in which case planning for grid expansion continues through a project-specific screening process proposed herein.*

   b. *Releasing Requests for Proposals (RFPs) for wires or non-wires solutions developed by parties other than the BPA Transmission Business Line.*

   c. *Deciding that location-specific and time-sensitive pricing of transmission service can defer construction of new transmission.*

   d. *Discussing with utilities and state regulators options for implement retail-pricing options to decrease the need for transmission expansion.*

   e. *Considering a broad package of alternatives with a range of the activities listed above (BPA, 2001).*

BPA has embarked on a comprehensive review of its Transmission Business Line policies, an action which requires review under the NEPA process, and since December 2003, it has been preparing the Transmission Business Policy Environmental Impact Statement. As a result of this environmental review and after it is complete (some time in 2005), BPA may expand its planning policies and process to include the elements shown above. The environmental review will also facilitate BPA's decision on whether or not to join an RTO (BPA, 2004).

Non-Wires Initiative

At the time of developing the 2001 infrastructure program, BPA recognized that the environmental review required during the NEPA process would require justification of the projects relative to alternative actions BPA could take to minimize impacts. To increase the likelihood of successful NEPA review for the infrastructure program, BPA sponsored a study that outlined methods to expand the planning process to consider non-transmission options (BPA, 2001).

The BPA non-wires initiative continues to assist the BPA planning process by seeking to identify further reliable and cost-effective alternatives to transmission expansion. The Transmission Business Line within BPA recognized that it could not implement non-wires solutions without involvement of a wide range of stakeholders, including at a minimum, the Power Business Line within BPA, other regional utilities, merchant power generators, regulatory commissions, and power customers. A round table group was formed in 2003 to begin coordination of these market participants (BPA, 2003).

In the 2001 study, BPA Transmission Business Line identified specific non-wires solutions to reduce peak transmission demand in certain sub-regions. The generally preferred non-transmission strategy was to shift or reduce the transmission load. A non-wires pilot program is underway in 2004 for the Olympic Peninsula where BPA would pay certain customers to curtail power purchases during peak hours. Through the program BPA hopes to achieve about 30 MW of deferred demand and potential generation (BPA, 2003).

Non-Wires Initiative Projects

BPA's May 2004 "Non-Wires Solutions Update" is available on the Internet at http://www.transmission.bpa.gov/PlanProj/Non-Construction_Round_Table/NonWireDocs/504Newltr.pdf. This newsletter describes several technology options and pilot projects that are in effect or in planning stages in the Pacific Northwest:

- **Load reduction pilot**. This program achieved voluntary demand reduction by major industrial facilities during periods of peak demand using an Internet-based trading platform. BPA posted an hourly price per MW, giving participants the chance to accept, reject, or counter the offer. In the four-day test, BPA was able to purchase an average of 22 MW of peak demand reduction during each hour of a simulated event. This reduction is equivalent to about one year's load growth in the test area.

- **Direct load control pilot**. BPA plans to use the "EnergyWeb" concept to integrate the utility electrical system with the telecommunications system and the energy market. The system would allow residential and commercial customers to control load by shifting energy use to lower-use time periods, reducing peak transmission loading. Commercial consumers will be able to reduce utility demand charges and residential consumers can receive utility rebates.

- **Distributed generation (DG) aggregation project**. BPA is testing DG technology as an element in a broad plan to defer construction of a new transmission line on the Olympic Peninsula. In this pilot program, DG would be triggered on an emergency basis, giving customers a day-ahead (or less) notice of the need for the start of DG. BPA has approached hospitals, local governments, utilities, and casinos to gauge interest in this project.

- **Load reduction and DG pilot.** In partnership with the DOE's Pacific Northwest National Laboratory, BPA will install remotely accessible load-shedding equipment and software in two commercial buildings to determine how much energy can be reduced for limited periods of time in a single building. BPA is also testing how major facility loads (i.e., air conditioning) can be turned off without major impact on systems. Another pilot will install a 30 kW microturbine in a commercial building and test how remote-access controls can be used to operate and monitor DG.

WHERE IN THE PROCESS SHOULD ALTERNATIVES BE CONSIDERED?

This question is one of the key topics for discussion in the June 14, 2004 IEPR Committee workshop. We would like to hear feedback on possible steps in the process in which alternatives can realistically be considered. Table 4 presents some steps in the current process; recommendations may be based on that description, or on any other system or process.

WHAT METHODOLOGY SHOULD BE USED TO CONSIDER ALTERNATIVES?

This question is the second focus of the June 14, 2004 IEPR Committee workshop. The goal of the workshop is to receive input on possible methods for development of a methodology that will allow reasonable consideration of alternatives to transmission. Methodology could address either of two timing phases:

- Early project planning - before final definition of the project
- Evaluation of alternatives in the CEQA process, in which alternatives must be evaluated consistent with CEQA requirements.

APPENDIX

A. Energy Commission and CPUC Studies and Proceedings

A.1 Energy Commission Planning and SB 2431

Transmission congestion and electricity reliability problems have traditionally been met by expansion of the electrical transmission system. Obtaining permission to expand an existing transmission right-of-way (ROW) or siting new transmission ROWs has been and continues to be a very difficult and controversial process. There are numerous entities (e.g., IOUs, independent power developers, transmission-dependent utilities, and transmission-owning utilities) involved in transmission planning, all with varying needs.

The Legislature, in an effort to avoid single-purpose transmission lines where possible and facilitate effective coordinated long-term transmission line corridor planning, approved Senate Bill (SB) 2431 (SB 2431, Stats. 1988, Ch. 1457), which required a number of electric utility transmission line ROWs studies to be prepared and included in the Energy Commission's 1990 *Electricity Report*.

The bill also made the following two general findings concerning the role of transmission in California's future development:

> a. The Legislature hereby finds and declares that establishing a high-voltage electricity transmission system capable of facilitating bulk transactions for both firm and non-firm energy demand, accommodating the development of alternative power supplies within the state, ensuring access to regions outside the state having surplus power available, and reliably and efficiently supplying existing and projected load growth, are vital to the future economic and social well being of California.
>
> b. The Legislature further finds and declares that the construction of new high-voltage transmission lines within new rights-of-way may impose financial hardships and adverse environmental impacts on the state and its residents, so that it is in the interests of the state, through existing licensing processes, to accomplish all of the following:

1. Encourage the use of existing ROWs by upgrading existing transmission facilities where technically and economically justifiable.

2. When construction of new transmission lines is required, encourage expansion of existing ROWs, when technically and economically feasible.

3. Provide for the creation of new ROWs when justified by environmental, technical, or economic reasons as determined by the appropriate licensing agency.

4. Where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity (to ensure that single-purpose lines are not constructed and any new transmission corridors can accommodate more than one transmission line).

Neither the need for transmission expansion nor the controversies surrounding expansion have diminished since the Legislature's transmission corridor siting findings were made. The Energy Commission believes that these principles are still important and must be considered when planning for the expansion of transmission corridors. A notice of a committee workshop for the preparation of the 2004 IEPR Update, lists the following potential drivers that the Energy Commission should consider when developing a collaborative vision for California's transmission system (Energy Commission, 2004a):

- Adherence to the transmission planning and siting principles developed in SB 2431
- Commitment to the development of renewable generation through the Renewable Portfolio Standard (RPS) program and other environmental drivers (see Section E of this Appendix)
- Assumptions regarding:
  - future availability of existing power plants;
  - future demand for electricity;
  - development of future in-state power plants, including distributed generation;
  - availability of out-of-state power plants to supply electricity to California; and
  - types and value of various strategic benefits not currently quantified in cost-benefit analyses.

A.2 Energy Commission's Corridor Viability/Environmental Fatal Flaw Study

In the *Electricity Report*, the Energy Commission adopted SB 2431 principles (see Section A.1 above), which values the minimization of environmental impacts when developers must expand transmission systems and specifies that planning and siting of new transmission facilities be pursued:

The Energy Commission is performing a Corridor Viability/Environmental Fatal Flaw Study aimed primarily towards legislature/decision makers, CA ISO, and IOUs. The availability of ROW is vital to the expansion of transmission infrastructure and use of the SB 2431 (see Section 5.1). Principles in ROW planning help to promote efficient use of existing infrastructure. The report includes Energy Commission staff study and findings in response to SB 2431 (proper use of the principles), as well as a background on utility practices over the last 10 years. The purpose of the report is:

- To establish use of SB 2431 Principles in assessing use and availability of infrastructure;
- To assess the expansion potential of existing ROWs in areas with near-term capacity expansion needs;
- To provide a reconnaissance-level review of siting constraints to expanding transmission rights-of-ways in Southern California (i.e., the Tehachapi area, San Bernardino County, Riverside/Imperial counties, and San Diego County); and
- To identify potentially significant issues which may limit the expansion of existing ROWs.

Energy Commission staff believes that Tehachapis, San Bernardino County, Riverside/Imperial Counties, and San Diego County have the most congestion in the state and would benefit the most from greater transmission capacity in these regions. In the approach and analytical method for the four transmission study areas, this report will describe how these subject areas have caused significant difficulties (e.g., significant mitigation, multi-jurisdictional approvals, etc.) in siting past transmission projects. The report will focus on the issue areas of biological resources (identification of sensitive natural areas, with stated policies restricting expansion of transmission facilities); cultural resources (identification of sensitive historic and prehistoric cultural resources the county); land use (identification of whether the governing agency(ies) have policies/goals/regulations regarding transmission lines and identification of populated areas surrounding transmission lines); visual resources (identification of established scenic corridors within the county which may be affected by expansion of identified transmission lines); and coordination of multiple jurisdictions. Health Effects (e.g., EMF) are generally described for all transmission lines since the analysis would be similar for any of the areas. Discussion from the 2003 Electricity and Natural Gas Report is also included.

Data sources include existing data layers on Energy Commission's GIS database (public lands, Native American owned land, Department of Defense, etc.), Department of Fish and Game (DFG) Natural Diversity Database, DFG's Natural Community Conservation Planning Data, DFG ecological reserves, Native American Heritage Commission, local agencies (e.g., planning departments, general plans), and Caltrans. Utilities and transmission owners within the defined study areas provided information on the location of existing transmission lines, existing ROW, owned land for future transmission facilities, opinions on the greatest obstacles to expanding transmission in their territories, and what else the utilities think should be studied (e.g., how wide of a corridor should be analyzed?).

The final report incorporates comments received during a public workshop into the technical body of the report, but it also includes an executive summary for decision makers. The Energy Commission completed this report in April 2004.

A.3 Energy Commission's Integrated Energy Policy Report

In the fall of 2002, the Legislature passed Senate Bill 1389 (Chapter 568, Statutes of 2002, Bowen) requiring the Energy Commission to prepare a biennial integrated energy policy report (IEPR). In passing SB 1389, the Legislature made clear that the IEPR would be the foundation of energy policies and decisions affecting the state. The statute directs state entities to carry out their energy-related duties and responsibilities based upon the information and analyses contained in the IEPR. During the spring of 2003, California's three principal energy agencies created a common vision to direct the future efforts at the CPUC, the California Power Authority (CPA), and the Energy Commission. As envisioned in the plan, the IEPR process represents "a critical step in identifying future statewide energy needs" (Energy Commission, 2003b).

On November 12, 2003, the Energy Commission adopted the 2003 IEPR. The IEPR consists of a policy report and three subsidiary volumes. In the policy report, the Energy Commission assesses the major energy trends and issues facing the state and uses these results to recommend energy policies that balance broad public interests to conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety.

The three subsidiary volumes address:

- Electricity and Natural Gas
- Transportation Fuels, Technologies, and Infrastructure; and
- Public Interest Energy Strategies

Senate Bill 1389 also requires the Energy Commission to adopt an IEPR every two years and an update every other year. This Energy Commission expects to publish the draft final 2004 Update to the 2003 Integrated Energy Policy Report (Docket #03-IEP-01) in mid-September 2004.

Coordination of Procurement with the Planning Process. A biennial cycle of common IOU procurement planning is being developed that allows use of the Energy Commission IEPR results, and the details will be examined as part of their 2004 long-term filings expected in spring 2004, which are to have a ten year time horizon.

IOUs are required to use Energy Commission IEPR demand forecasts as the base case, but they have the option to choose an alternative as their base case as long as they justify this choice. If an IOU chooses an alternative, it must still use the Energy Commission's views as one scenario. A wide range of alternative scenarios must be filed to cover various uncertainties at both the service area and regional level, including fuel price uncertainty.

IOUs must develop and implement programs to ensure that actual delivered energy efficiency impacts meet or exceed those which were planned, which will require improved measurement and evaluation efforts. IOUs must also include a local reliability component in their next long-term plan.

A.4 CPUC Order Instituting Rulemaking on the Transmission Assessment Process

The planning, siting and construction of transmission projects by IOUs in California is largely governed by the CPUC's General Order (GO) 131-D. GO 131-D prescribes a permitting process for construction of both generation and electric transmission facilities, including the decision on project need. GO 131-D also provides that construction of transmission facilities 200 kV and above cannot commence without a finding that there is no significant environmental impact or that the project is exempt from CEQA, or without adoption of a Final EIR or a Negative Declaration.

Under an OIR (R.04-01-026) issued on January 22, 2004, the CPUC is proposing to amend GO 131-D to defer to the CA ISO regarding economic need and reliability need determinations and is anticipating a final decision in fall 2004. CPUC intends to address claims that the existing transmission review process promotes inefficiencies and unnecessary redundancies in the current transmission review process. Overall the CPUC is hoping to streamline the transmission assessment process. The CPUC would still conduct CEQA, validate the CA ISO's need determination, conduct comprehensive planning, and to the extent that the CA ISO uses an agreed upon standard for assessment the CPUC will not revisit the question of need in the CPCN process.

In the OIR, the CPUC claims that "the changes would allow the CPUC to apply a universal economic methodology for economic transmission projects, once it is adopted, in a way that eliminates duplicative transmission need determinations that currently exist at the CA ISO and the CPUC. Under the proposal the CPUC would utilize the CA ISO's need determination for reliability projects to the degree there is an agreed upon standard and the CA ISO applies that standard" (CPUC, 2004b). The CPUC has asked the CA ISO to propose a standard for determining need for a transmission project to maintain or enhance system reliability so that parties have the opportunity to comment. Interested parties are currently commenting on the CPUC's OIR and CA ISO proposed need standards.

The Riverside Parties believe that CA ISO determination of need should not solely rest with CA ISO, and it should be subject to cross-examination before the CPUC. They state: “As the [Public Utilities] Commission itself recently stated, deferring to the ISO on the question of need "would constitute an unlawful delegation of our authority, giving the ISO power that the Legislature has not bestowed on it." [D.03-05-038 (May 8, 2003) related to the SDG&E Valley-Rainbow 500 kV Interconnect Project.] The Legislature has, in Section 1001 of the Public Utilities Code, imposed on the CPUC the obligation to determine whether a major new transmission line is needed and nothing has changed since that was enacted.” (from Riverside Parties position on CPUC GO 131-D amendments.)

A.5 CPUC Order Instituting Rulemaking on Resource Planning

In a rulemaking that began in October 2001, the CPUC has been working to return the energy procurement function to IOUs and displace the state agency that temporarily undertook that function when the IOUs filed for bankruptcy. On January 22, 2004 the CPUC issued a decision (D.04-01-050) directing utilities and other load-serving entities to prepare to increase their generation reserves to 15 percent of peak demand by January 1, 2008. Although the decision said that the utilities must meet 90 percent of that goal a year in advance, it did not give specifics about how the utilities were to accomplish this (Stanfield, 2004).

Therefore, on April 1, 2004, in an effort to address specifics, the CPUC opened an Order Instituting Rulemaking (OIR) (R.04-04-003) to continue efforts to integrate electric utility resource planning of the state’s three major electric IOUs (PG&E, SCE, and SDG&E). This central planning-style “umbrella” OIR is intended to ensure policy consistency, cohesiveness, and overall coordinated review of the long-term procurement plans in conjunction with the following related working dockets:

- Community Choice Aggregation [R.03-10-003];
- Demand Response [R.02-06-001];
- Distributed Generation [R.04-03-017] (in collaboration with Energy Commission Docket 04-DIST-GEN-1 and 03-IEP-1);
- Energy Efficiency [R.01-08-028];
- Avoided Cost and Qualifying Facility (QF) Pricing [rulemaking to be issued shortly];
- Renewable Portfolio Standards [R.04-04-026] (see Appendix, Section E);
- Transmission Assessment Process [R.04-01-026]; and
- Transmission Planning [I.00-11-001].

On March 8, 2003, the Energy Commission, the Consumer Power and Conservation Financing Authority (CPA), and the CPUC approved an Energy Action Plan (EAP) in addition to the Renewable Portfolio Standard. In the rulemaking, the CPUC will use this interagency EAP as a guide[2] (CPUC, 2004a). The shared goal of the Energy Action Plan is to:

> *"Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers."*

The EAP envisions the following loading order of energy resources:

- First seek to optimize all strategies to increase conservation and energy efficiency in order to minimize increases in electricity and natural gas demand.
- Then, meet demand for new generation with renewable energy resources and distributed generation.
- Then because preferred resources require both sufficient investment and adequate time to "get to scale," the EAP supports additional clean, fossil fuel, central-station generation.
- Finally, the EAP intends to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation.

This loading order is the standard against which the long-term plans will be considered, but it does not preclude the CPUC from considering other options, particularly redevelopment of existing facilities, to the extent new generation resources are required (CPUC, 2004a)

In this proceeding, the utilities will submit their long-term procurement policies and plans for review and approval. The umbrella rulemaking will require detailed proceedings involving other agencies, such as the Energy Commission, CA ISO, and CPA. Although review and adoption of long-term procurement plans is the main objective of this rulemaking, the order stated that the proceeding is also the forum for review of resource adequacy issues; utility procurement incentives; long-term policy issues surrounding expiration of QF contracts; management audits of SDG&E's and PG&E's electric procurement transactions with affiliates; and treatment of confidential information (CPUC, 2004a). In addition, until the CPUC issues a separate rulemaking on avoided cost issues, this proceeding will serve as the forum for coordinating the CPUC's development of avoided costs across the various resource-related proceedings. The CPUC believes that this rulemaking is the

[2] *Energy Action Plan*, adopted April 18, 2003 by the CPA; April 30, 2003 by the Energy Commission; and May 8, 2003 by the CPUC. A copy of the Energy Action Plan is available at www.cpuc.ca.gov/static/industry/electric/energy+action+plan/index.htm.

successor to the current procurement rulemaking on long-term resource plans for PG&E, SCE, and SDG&E and hopes that it will be used to develop a statewide resource-planning framework.

B. CA ISO Proceedings

B.1 CA ISO Controlled Grid Study

The Grid Planning Department of the CA ISO annually performs a reliability assessment of the CA ISO controlled bulk system transmission grid for future operating scenarios to determine the need for transmission expansion projects. The CA ISO uses the information in the Transmission Expansion Plans from the three IOUs (see Section 2.1.1 above), in developing the CA ISO Controlled Grid Study, which focuses on the overall system and bulk transmission under CA ISO control. New transmission projects that have received ISO approval are modeled in the study. The main section of the report provides summaries of the study assumptions, conclusions, and recommendations. The appendices contain the detailed assumptions, study results, conclusions and recommendations.

The CA ISO Planning Standards that are incorporated into the study plan include the following (CA ISO, 2003b):

1. NERC/WECC Planning Standards - The criteria specified in the NERC/WECC Criteria for Transmission System Planning unless NERC/WECC formally grants an exemption or deference to the CA ISO.
2. Specific Nuclear Unit Standards - The criteria pertaining to the PG&E's Diablo Canyon and SCE's San Onofre Nuclear Power Plants.
3. Additional Line and Generation Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.
4. San Francisco Greater Bay Area Generation Outage Standard.

The 2002 CA ISO Controlled Grid Study recommended the following:

- Upgrades to the 115 kV system at the PG&E San Mateo Substation.
- Improvements to the 115 kV line between PG&E Swift and Metcalf Substations.
- Improvements and operational changes by SCE, SDG&E, and CA ISO to upgrade the 500 kV line between Hassayampa and North Gila.
- Further study of options for the LADWP portion of the 500 kV line between Lugo and Victorville (CA ISO, 2003b).

A report summarizing the results of the 2003 CA ISO Controlled Grid Study is currently being prepared and should be available for stakeholders before June 2004.

B.2 Southwest Transmission Expansion Plan

The Southwest Transmission Expansion Plan (STEP) was created as an ad-hoc subregional planning group to address transmission concerns in the Arizona, southern Nevada, southern California, and northern Mexico area. It was formed because It was clear to many of the STEP participants that the existing transmission system in this area was inadequate to fully deliver all the new generation that has been developed. By enhancing the capability of the system, this new, cleaner, and efficient generation would be better able to serve future load growth and displace older and less efficient generation.

STEP held its first meeting on November 1, 2002 in San Diego and has met on a monthly basis since that meeting. Participants include representatives from utilities, independent power producers (IPPs), state agencies/regulators and other stakeholders with an interest in the transmission system in southern Nevada, Arizona and southern California. Shortly after STEP's formation, the group adopted the following goal:

> *"To provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, Southern Nevada, Mexico, and Southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The wide participation envisioned in this process is intended to result in a plan that meets a variety of needs and has a broad basis of support."*
> (STEP, 2004)

As can be seen in the above goal, STEP's focus is on economically driven expansion projects that support the development of seamless west-wide markets while satisfying established reliability standards.

Over its first year, STEP conducted both technical (power flow and stability) and economic (production cost) studies. To develop transmission projects to mitigate inefficient congestion on the system, STEP evaluated more than 25 different upgrade scenarios. Based on the technical and economic studies and a consensus building process, this large number of initial alternatives was narrowed down to one general expansion plan. STEP has now begun implementing several of the initial projects that can be implemented quickly and economically. A separate sub-group of STEP was formed to focus on these short-term upgrades. The initial steps primarily involve upgrades to the series capacitors in several existing 500 kV lines.

During 2004, STEP expects to have some of the larger system upgrades agreed upon and to initiate their implementation. In fact, one of STEP's primary goals in 2004 will be to identify the preferred project for a new transmission line into San Diego.

Another sub-group of STEP was tasked with developing a final plan for a new line between Arizona and California. Similarly, another sub-group is currently working on a new transmission line into San Diego. The planning and development of these two projects will take place in parallel. These larger scale upgrades involve the construction of major new 500 kV lines. Altogether, the total cost of the economic transmission additions being developed by STEP is estimated to exceed one billion dollars.

From 25 original transmission alternatives, six alternatives became the subject of detailed analyses. The additional analyses led to the sequence of upgrades and additional studies that are underway, and may change the transmission expansion plan. The expansion plan includes short-term and San Diego–area upgrade options, as well as a new line between Arizona and California and a new line into San Diego for economic and reliability need following the completion of short-term upgrades. Each project will also have to undergo a cost-benefit analysis and will move forward only if found to have sufficient overall benefits to offset their costs (except for the San Diego–area upgrades, which already have CA ISO Board approval).

STEP published a final interim 2003 status report in May 2004 that documents the activities of the STEP subregional planning group during its first year of operation together with the interim transmission expansion plan that STEP has produced. STEP will remain active as a sub-regional planning forum even after the initial transmission concerns are addressed and implemented to help ensure that the future transmission grid in this area is developed in a coordinated and efficient manner.

B.3 Reliability Must-Run (RMR) Assessment

Over the years, generation and transmission expansion projects have been built to serve increasing consumer load growth. These projects were integrated with the facilities that preceded them. In many cases, certain generation-related components, in whole or in part, complement transmission-related components. Generation-related components benefit the transmission grid in several ways, including providing voltage support, reducing heavy power flows on certain transmission lines, and minimizing the oscillatory nature of the electric system (CA ISO, 2003c). In these situations, generation and transmission facilities are interdependent in maintaining grid reliability.

California's restructured electric market potentially allows for the temporary absence or permanent elimination of certain generators from the transmission grid. However, as noted above, there are certain situations where generation and transmission facilities are interdependent. In these cases, where the absence of some generating units could compromise reliability in different ways, including reduced voltage support on the system and increased thermal loading of transmission facilities. A generating unit whose absence could have a detrimental impact on reliability in a discrete local area under specified operating conditions is categorized by the CA ISO as a "Reliability Must-Run" (RMR) generating unit.

The development of the RMR requirements is attained through an annual coordinated stakeholder effort managed by the CA ISO. RMR studies are performed in order to determine the minimum megawatts of market generation required to be online in identified local areas in order to be able to reliably serve the load. The annual RMR study evaluates the transmission grid under heavy summer operating conditions in the upcoming year with a singular focus on determining RMR requirements in the RMR areas identified in previous RMR studies, as well as any new RMR areas that were identified during the previous year.

There are two types of RMR areas. The first type is defined as a “Generator Deficient” area. This type of area exhibits violations to the RMR criteria even when all available generation resources are in service within the area. In this RMR study, additional analyses would be conducted to provide an estimate of the total RMR requirement by finding the generator deficiency (through generator or load proxies) and adding the deficiency to the aggregate generation for each generator deficient RMR area. Examples of Generator Deficient areas are the Battle Creek Area, the Eagle Rock and Fulton Subareas in the North Bay Aggregate, the Placer Subarea in the Sierra Aggregate, the Lockford Subareas in the Stockton Aggregate, and the Reedley Subarea in the Fresno Aggregate. The second type is defined as a “Competitive Area”. Here there is more market generation then what is strictly required to run in order to reliably serve the load in this local area (CA ISO, 2003c). Examples of Competitive areas are the Greater Los Angeles Basin, the Ventura and Chico Areas, and subareas such as Lakeville and Summit.

The completion of the RMR process is achieved through the Local Area Reliability Service (LARS) process. The LARS initiative is the process by which the CA ISO determines how to mitigate local area reliability problems. To initiate the LARS process, the CA ISO staff conducts a technical study to determine which specific areas within the CA ISO controlled grid exhibit local reliability problems and the technical requirements necessary to mitigate identified local reliability problems. The CA ISO then issues a Request for Proposal (RFP) that can satisfy the requirements. Market participants are encouraged to submit alternatives to RMR generation to satisfy the LARS megawatt requirement for each identified LARS area. The CA ISO considers generation, transmission and demand-reduction proposals. CA ISO staff then evaluates the alternatives and compares them on a cost-effectiveness basis, subject to certain constraints such as operating characteristics, among others. The CA ISO also considers transmission projects submitted by the IOUs or participating transmission owners through their annual transmission assessments, which are discussed in Section 2.1.1 above. Based on these considerations, CA ISO management presents a list of preferred alternatives to the CA ISO Board for approval (CA ISO, 2003c).

A screening process follows to eliminate identified units from the Unit Candidate list based on a set of principles involving contractual relations and exemptions due to generator unit size (e.g., currently units less than 10 MW). The resulting new “Unit Eligibility” list represents unit candidates that are eligible to receive an RMR contract. This screening process is part of the LARS process.

Units on the Unit Eligibility list are then compared to other generation, transmission and demand-side proposals in the LARS RFP process. The LARS RFP process is the final step in selecting and presenting the preferred RMR mitigation alternatives to the CA ISO Board for approval. In response to the LARS RFPs made public by the CA ISO, the transmission owners and interested stakeholders are encouraged to submit competitive proposals to mitigate RMR criteria violations.

As a result, each year the CA ISO publishes a RMR report, which details the CA ISO's technical studies that were performed to identify RMR requirements and RMR generator unit candidates for the upcoming year. The assessment process includes investigation into potential RMR-related reliability impacts in local areas that are internal to the CA ISO Controlled Grid. The most recent assessment (for 2004) focused on those areas and sub-areas identified in RMR studies for 1999 and verified and revised (as necessary) in the 2000, 2001-03, 2002-04 and 2003 RMR studies. As required, additional studies were conducted to address new reliability concerns within RMR local areas and sub-areas. It is expected that the 2004 RMR results, which were published in May 2003, will be the basis for one-year (2004) RMR contracts (CA ISO, 2003c). The 2005 RMR results are expected to be released in May 2004.

B.4 Transmission Economic Assessment Methodology

Established in September 2001, the goal of the Transmission Economic Assessment Methodology (TEAM) is to establish a common methodology for assessing need and economic benefits of major transmission upgrades and expansion in a restructured market environment to be used by California regulatory agencies, such as CA ISO, CPUC, and Energy Commission. The workgroup is sponsored by CA ISO and is currently working to expand the stakeholders in the CA ISO planning process and implement recent policies of the CPUC (relating to investigating implementation of AB 970, CPUC Proceeding No. I.00-11-001) and Energy Commission (identified in the IEPR).

Unlike the vertically integrated regime that existed prior to restructuring, the restructured wholesale electric market involves a variety of parties making decisions that affect the utilization of transmission lines. This paradigm shift requires a new approach to evaluating the economic benefits of transmission expansions. Specifically, a new approach must address the impact that a transmission expansion would have on increasing transmission users' access to generation sources and demand areas, the impact on incentives for new generation investments, and the impact on increasing market competition (CA ISO, 2004d). It must also address the inherent uncertainty associated with other critical market drivers such as future hydroelectric generation conditions, natural gas prices, and demand growth, as well as capturing the dispatch capability of hydroelectric generation and the availability of import supplies. These last two factors are particularly critical in modeling the California market given its heavy dependence on hydroelectric generation and imports (CA ISO, 2004d). The key principles of the methodology include evaluation of the following, especially for proposed large inter-regional upgrades (CA ISO, 2004b):

- **Benefits Framework**. Establish a standard framework to measure benefits regionally and separately for consumers, producers, and transmission owners in different regions.
- **Market Prices**. Utilize market prices to evaluate expansion while evaluating the impact of transmission expansion on market competitiveness and the interdependence of generation and transmission investments.
- **Uncertainty**. Consider a wide range of future system conditions, such as dry hydro, gas prices, demand growth, and under-and-over entry of generation.
- **Network Representation**. Demonstrate that flow is physically feasible using a full network model with data provided by WECC.
- **Generation/Demand-Side Substitution**. Evaluate alternatives to transmission expansion.

The blueprint of the general methodology was developed jointly by CA ISO and London Economics LLC with more than a year of research and development using a proposed expansion of Path 26 as an illustrative case study. It was filed with the CPUC in February 2003. Input and review was provided by the CA ISO Market Surveillance Committee, as well as a Steering Committee made up of representatives of the IOUs (PG&E, SCE, and SDG&E) and representatives from various state agencies, including the CPUC, Energy Commission, and Electricity Oversight Board (CA ISO, 2004c). The group is developing scenario input data and performing sensitivity cases in an effort to develop testimony and review to submit to the CPUC in early June 2004 (for CPUC Proceeding No. I.00-11-001).

C. Transmission Projects not Sponsored by an IOU

Over the next five years there will be a continuing need for additional transmission capacity expansions to increase electricity import into California, support new generation, and mitigate congestion. The IOUs annual transmission plans identify numerous projects that are being considered for either meeting reliability standards, reducing congestion, or improving flexibility (addressed above). Until implementation of a new market mechanism, mitigation of inter- and intra-zonal congestion will continue to be handled by CA ISO in real time. The most significant congestion is now the Mexican generation connected at Imperial Valley substation, where congestion charges roughly average $88,000 per day (CA ISO, 2003a). Other transmission constraints that often require flow mitigation actions include the Southwest Power Link (SWPL), Path 26, South of Lugo, the total Southern California Import Transmission (SCIT), and the California-Oregon Intertie (COI).

There are various transmission system improvements approved or underway to reduce the amount of inter and intra-zonal congestion and to mitigate various local area constraints. These projects are not consolidated or listed in any single report or assessment. From review of submittals to CA ISO and CPUC, projects from the three major IOUs are highlighted in Section 2.1.2 above. Five other possible projects that are not included in the IOU expansion plans are described below.

C.1 City of Pittsburg/Babcock & Brown Trans-Bay Cable Project

Babcock & Brown Operating Partners, City and County of San Francisco (CCSF), and the City of Pittsburg are collaborating on plans to develop a 50-mile, 350 MW DC transmission line that would stretch from the City of Pittsburg in Contra Costa County to the CCSF. Babcock & Brown would finance the project and claim some of the transmission rights. Pittsburg Power Company, the City of Pittsburg's municipal utility, would share transmission rights and own and operate the line. PG&E would also have transmission rights, which would pay for system upgrades it would need to complete, such as the AC/DC adaptors needed at each end of the line. The Trans-Bay Cable project would allow power to be brought directly into San Francisco from the East Bay, instead of the current practice of sending it south to Santa Clara County and then north up the peninsula. The new cable would also provide more redundancy for the existing grid.

Due to the large number of power plants in the Pittsburg area, the system cannot handle the power flows if all of the plants operate at optimum capacity. In Pittsburg, there are three operating merchant plants and eight qualifying facilities under contract to PG&E. Calpine Corporation owns 1,470 MW, Mirant Corporation owns 2,020 MW, and GWF Energy owns approximately 1,900 MW of qualifying facilities (QFs) and peakers. South of Pittsburg, in San Jose, Calpine owns 346 MW of QFs and peakers, and its 600 MW Metcalf plant is scheduled to become operational in 2005 (Platts, 2004). Pittsburg Power Company, prospective owner of the Trans-Bay Cable project, does not own generation. Pittsburg Power Company was formed in 1996 when it acquired the Mare Island distribution system from the U.S. Navy. Currently, PG&E provides power to the Pittsburg area.

There are several route alternatives under consideration for the cross-bay line. The three general options include a submarine cable across the San Francisco Bay, use of the BART corridor and trans-bay tunnel, and use of the railroad ROW. The proponents have just recently opened discussions with state agencies (e.g., CPUC, CA ISO), which would need to approve the project, and with PG&E. The Trans-Bay Cable Project offers the DC line as an alternative to the construction of another generating plant in the San Francisco Bay area in an effort to relieve existing congestion both coming out of Pittsburg and going into CCSF. Furthermore, the project would reduce the need for RMR contracts and eliminate costs to operate the greater San Francisco-area grid, according to Babcock and Brown (Platts, 2004). Advantages of a DC line are that it can provide black-start capability, and with some technologies, can provide reactive power. However, the line would require alternating current/direct current converters at each end, which would increase costs and land requirements.

Thus far Babcock & Brown and the City of Pittsburg have briefed CA ISO and PG&E on their plans. The CA ISO would need to determine the transmission need based on project reliability and/or economic viability. In addition, the parties have met with the CPUC, which would need to approve changes in PG&E transmission tariffs to help pay for the project. Babcock and Brown plans to file its application for environmental and other permits by June 2004 and receive the necessary approvals to begin construction by the middle of 2005. Based on this schedule, the Trans-Bay Cable project could be operating by the second or third quarter of 2007.

C.2 Western Area Power Administration

WAPA has been involved in coordinating the proposed interconnection of eight merchant plants in California to its grid, which is interconnected with the system operated by CA ISO. Two notable transmission system upgrades are in progress within the California portion of the WAPA system, and numerous other projects are underway in other western states.

WAPA recently completed environmental assessment of the Sacramento Area Voltage Support project, which would reconductor a 230 kV line between the Elverta and Tracy Substations and construct a new 230 kV line between the O'Banion and Elverta Substations. Construction of this expansion could begin in 2004. Also, WAPA, Trans-Elect Inc., and PG&E are jointly carrying out the Path 15 upgrade project with a new 500 kV transmission line. The Path 15 project obtained FERC and CA ISO approval in 2002, and it is scheduled to come online in late 2004. The project will be operated as a transmission facility within the CA ISO.

C.3 Sacramento Municipal Utility District

The Sacramento Municipal Utility District (SMUD) is a public utility that provides electric power to Sacramento County and a small part of Placer County. SMUD gets its electricity from diverse and competitively priced resources, including hydro generation, cogeneration plants, and renewable technologies such as wind, solar and biomass/landfill gas power, and power purchased on the wholesale market. SMUD is not a member of CA ISO, and it operates a transmission control area that is independent of CA ISO. Because it is not a CA ISO-participating transmission owner, SMUD is not required to develop an annual transmission grid expansion plan. As a public utility, SMUD is not subject to regulation or oversight by the CPUC (SMUD, 2003), but federal regulations apply, including existing requirements for annual operational reviews and possibly future market design requirements that would mandating a codified planning process.

SMUD is planning three sub-regional power line projects, and it is also in the early phase of developing a resource plan that addresses future acquisition, generation, and transmission of power to its customers. SMUD accepted public scoping comments this planning effort through April 2004. The forthcoming resource plan is expected to address projects that avoid substantial transmission expansions such as development of local renewable generation and "clean" distributed generation. The environmental review process is underway for the following projects (SMUD, 2004). The three power line projects are;

- Airport–San Juan neighborhood distribution substation and associated 4.8-mile 69 kV sub-transmission lines
- Folsom Golf Links Substations and interconnecting 69 kV power line loop
- Elkhorn-Natomas Distribution Substations and interconnecting 69 kV power lines

C.4 Lake Elsinore Advanced Pumped Storage Project (LEAPS)

The LEAPS project would pump water from Lake Elsinore at night and generate 500 MW of electricity during the day at peak energy-use times. It is proposed by Elsinore Valley Municipal Water District (EVMWD) and Nevada Hydro Company, and consists of the following components:

- A new upper reservoir (Morrell Canyon) having a 180-foot-high main dam and a gross storage volume of 5,760 feet, at a normal reservoir surface elevation of 2,760 feet above mean sea level (msl).
- A powerhouse with two reversible pump-turbine units with a total installed capacity of 500 MW.
- The existing Lake Elsinore to be used as a lower reservoir.
- About 30 miles of new 500 kV transmission line connecting the project to an existing transmission line owned by SCE located north of the proposed project and to an existing SDG&E transmission line located to the south.

The FERC is the Federal Lead Agency charged with reviewing the project and granting LEAPS a license to build and operate in California; the EVMWD is the CEQA Lead Agency,

The LEAPS project will help stabilize the lake level, which will help increase recreational use of the lake during the summer season, a key staple of the local economy. It will also provide a water reservoir for fighting fires in the Cleveland National Forest. Regardless, the Forest Service has expressed significant concerns about the impact that the project (particularly the new transmission lines) would have on visual resources.

Although not proposed for this function, EVMWD's LEAPS can also be viewed as an alternative to the SDG&E Valley-Rainbow 500 kV Interconnect Project, since that project has been terminated. The need for Valley-Rainbow was first identified by CA ISO in conjunction with SDG&E, but later rejected by the CPUC. The same transmission corridor through the National Forest that is defined in Congressman Issa's bill HR 5409 (intended to facilitate construction of the Valley-Rainbow project) could be used. LEAPS has moved slowly because it has faced opposition from local homeowner groups, business, recreational groups and environmental groups. Currently the licensing process underway deals with both the hydroelectric plant and the transmission lines that would be used to connect that plant to the electric grid. There has been discussion at the EVMWD Board and at CA ISO of having this transmission route be a substitute for the originally proposed Valley-Rainbow project. The EVHWD Oversight Committee has asked the EVMWD Board to respond to the potential to build the line only. There has been no official response as yet from EVMWD.

D. Federal Context and Other Regions

D.1 Consideration of Alternatives: Need for Coordination

Finding workable alternatives to transmission upgrades depends on the early identification of needed improvements by grid operators or owners, followed by coordinated participation of commissions, planning agencies, and other stakeholders. The process for assessing transmission alternatives becomes more complicated when state boundaries are crossed or when numerous land management agencies are involved. Nation-wide, there is a well-recognized need for coordinating transmission planning.

D.1.1 U.S. DOE – National Transmission Grid Study

The U.S. Department of Energy in its 2002 *National Transmission Grid Study* (NTGS) recognized that ongoing structural changes in the electricity industry raise important issues about transmission planning and the need for new transmission capacity. The study called for integration of planning for transmission, generation, and demand-side management programs. It also specifically recognized that a need exists for consideration of non-transmission alternatives that could meet reliability requirements and commercial needs (U.S. DOE, 2002).

The NTGS cites the 163-mile Sierra Pacific Power Company's Alturas Transmission Line as an example of how reaching consensus between agencies with varied responsibilities can cause extensive delays and increased costs. Sierra Pacific estimated that delays in federal Forest Service permitting cost the project two years and an additional $20 million.

D.1.2 National Governors Association – Interstate Strategies for Transmission

Another 2002 study was conducted by the National Governors Association's (NGA) Task Force on Electricity Infrastructure, providing a collection of policy recommendations for transmission planning. The NGA cites the 113-mile American Electric Power transmission line between West Virginia and Virginia as an example of how selecting a preferred transmission line route can substantially delay a siting project. In that case, competing state and federal agencies and sequential, rather than parallel, review of alternative routes have resulted in the siting process extending over ten years (NGA, 2002).

D.1.3 Study by Consortium of Electric Reliability Technology Solutions

Within California, the need for coordination is also well documented. The Energy Commission consultants, Electric Power Group and Consortium of Electric Reliability Technology Solutions (CERTS), identified a need for reconsidering or revising the current transmission system planning methodologies. The CERTS report notes that the planning horizon for transmission interconnections currently focuses on power needs within a three to five year window, but that major transmission expansions have approximately at ten-year lead-time. It also notes that reliable information on development of new generation projects (e.g., from merchant power providers) is lacking.

The CERTS report encourages developing a unified vision and strategic plan for future interconnections. It envisions California working together with neighboring regions to develop corridor and right-of-way plans, possibly by banking secured rights-of-way for future use, and to streamline the siting and permitting process for multi-state projects. It recommends streamlining and coordinating planning and permitting with two basic phases: a strategic planning phase, which would build consensus on the need for interconnections within a 25-year horizon, and a permitting phase, which would focus on specific projects needed within a 5 to 10-year horizon (Energy Commission, 2004b).

D.2 Role of the FERC in Transmission Planning

The Federal Energy Regulatory Commission (FERC) is responsible for developing electricity markets that produce fair and reasonable prices and reliable service for customers. This effort to standardize markets has evolved for more than a decade through a series of orders from the FERC and restructuring initiatives in various states. Initially, this established wholesale power markets and led to the creation of numerous independent transmission providers (or ISOs) throughout the country. More recently, there is an evident need for the markets to be structured with fair behavioral rules, effectively monitor themselves, mitigate prices that are unlawful, and provide a level playing field for all market participants. Ongoing efforts to harmonize wholesale power markets attempt to assure the availability of critical infrastructure (FERC, 2003).

Rulemaking currently being contemplated by the FERC recognizes that the function of regional transmission planning and expansion is essential for a well-functioning wholesale market. Transmission system operators are in a unique position to discern regional needs. They may also be able to address factors inhibiting investment in transmission and generation through conducting a region-wide planning process. The FERC currently believes that transmission operators should produce technical assessments of the regional grid and support the state siting authorities or multi-state entities by performing the studies necessary to establish need for transmission expansions. The planning process should give the states and market participants an independent assessment of the transmission facilities needed by the region to reliably and economically serve load located within the region. The FERC also believes that the transmission operators should have a formal regional planning process in place as soon as practicable (FERC, 2003).

FERC Order 2000 and the RTO. According to FERC Order 2000 (issued December 20, 1999), regional transmission organizations (RTOs) would have the ultimate responsibility for transmission planning and expansion at a regional level. Because the FERC recognized that expansions sought by an RTO would need to comply with state and local requirements, FERC Order 2000 allowed a three-year period for each RTO to establish and implement a planning and expansion process that would be consistent with state and local statutes regulating siting of transmission facilities.

An RTO can be any of several types of transmission overseers, including independent system operators, regional transmission groups, and transmission companies. In order for the system operator to qualify as an RTO, the transmission planning and expansion process to be followed by the operator must be codified. There is currently no RTO in California or the western states. The CA ISO, Grid West in the Pacific Northwest (formerly RTO West), and WestConnect in the Southwest (formerly DesertSTAR) are each independently taking steps toward approval as either independent RTOs, or a combined multi-regional RTO.

Quote from FERC Order 2000 (p.486): The RTO must have ultimate responsibility for transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service…the rationale for this requirement is that the single entity must coordinate these actions to ensure a least cost outcome that maintains and improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability.

Opinion of a merchant power producer in response to FERC Order 2000: For situations where RTOs could not gain permission from state and local commissions for expansions, the FERC and the RTO would have no legal or regulatory authority to compel the state commission to act in a different manner. In response to such situations, the FERC expected that state and local utilities would make “good faith efforts” to achieve expansions sought by RTOs (FERC Order 2000-A, February 25, 2000).

D.3 Role of WECC in Transmission Planning

The Western Electricity Coordinating Council coordinates and promotes electric system reliability for all of the western region of the U.S. and parts of Canada. WECC is a regional reliability council (a voluntary organization of transmission owners, transmission users, and other entities) that is approved by the FERC to coordinate transmission planning and expansion, and operation on a regional basis. It has a region-wide focus that is intended to complement the development of Regional Transmission Organizations. Examples of WECC members (Class 1 Transmission Providers) are: CA ISO, WAPA, BPA, PG&E, SCE, and SDG&E.

Other municipal utility districts (SMUD, Cities of Redding, Riverside, Anaheim) and irrigation districts (Imperial Irrigation District, Modesto Irrigation District) are also transmission provider members.

The North American Electric Reliability Council (NERC), the parent organization of WECC, establishes the minimum transmission planning standards. According to the Regional Planning Guidelines, each project that has significant regional impacts must take into account alternatives that use the existing transmission system or upgrades. Regional projects must also address the feasibility of alternatives (WECC, 2002).

Depending on the activities of the Seams Steering Group-Western Interconnection (SSG-WI) and the ongoing development of RTOs in the western states, the WECC Procedures for Regional Planning Project Review will likely need to be changed accordingly. Seams are boundaries between control areas that could lead to disruptions in transmission. Merging present control areas into RTOs to reduce seams would require reorganization or consolidation of how WECC members share planning information.

Since 1991, participation in the WECC regional planning process by members has been voluntary. When a WECC member sponsors a project and releases it to the, the WECC staff provides an opportunity for other members, regulators, or environmental groups to comment on the project and identify alternatives to significant additions, including non-transmission alternatives. All projects or alternatives identified by sponsors or other parties must meet the NERC/WECC reliability standards.

D.4 Planning and Alternatives Processes Beyond the CA ISO

D.4.1 Western Area Power Administration

The Western Area Power Administration, a federal power marketing administration, sells wholesale power and delivers bulk wholesale transmission to local utilities from 56 power plants operated by the Bureau of Reclamation, the U.S. Army Corps of Engineers and the International Boundary and Water Commission. Created in 1977, WAPA currently markets and transmits power throughout a 1.3 million square mile service territory to more than 600 customers, including rural electric cooperatives, municipalities, public utility districts, federal and state agencies, and irrigation districts.

The mission of WAPA is to market and deliver reliable, cost-based hydroelectric power and related services. The Desert Southwest Region is one of four regions within WAPA that sells power in southern California, Arizona, and southern Nevada. The Sierra Nevada Region (SNR) sells power in northern and central California and portions of Nevada, to wholesale customers. Other WAPA regional operations cover transmission facilities in Iowa, Minnesota, Montana, Nebraska, North Dakota, South Dakota, Colorado, Wyoming, Nebraska, and Kansas.

WAPA is currently working with transmission operators inside California and elsewhere in the western states to evaluate the costs and benefits of various options for forming an RTO. WAPA also participates in the Seams Steering Group-Western Interconnection (SSG-WI) workgroup to discuss the possible RTO strategy and procedures for transactions among transmission operators.

For the portions of the WAPA transmission system that are not used by federal customers, WAPA offers open access. WAPA is not a public utility under the Federal Power Act, and it is not specifically subject to FERC orders related to market restructuring. It is however a transmitting utility subject to the FERC's annual transmission planning and evaluation requirements. Except for these routine operational reviews, WAPA is not required to have a codified transmission planning process.

The WAPA Open Access Transmission Service Tariff approved by the FERC in 1998 (63 FR 521) currently dictates the availability of the WAPA's federal transmission facilities to California's transmission operators. Customers needing the service and capacity of WAPA's system must initiate the transmission service request according to the Open Access Transmission Service Tariff. Service requests to WAPA dictate when expansions to the system would be necessary. Direct interconnection to WAPA's system alone, without a service request, would not guarantee access to transmission service and capacity.

Transmission and non-transmission alternatives are reviewed when WAPA responds to a service request. If WAPA determines that it cannot accommodate a request for transmission service because of insufficient capability on its system, WAPA must use due diligence to expand or modify its system to provide the requested service, provided the customer agrees to compensate WAPA in advance for costs (WAPA Tariff §15.4). In determining the need for new facilities and in the design and construction of such facilities, WAPA must conform to Good Utility Practice. WAPA must also conform to Good Utility Practice in its efforts to plan and construct new facilities to meet the "network" load (WAPA Tariff §28.2).

WAPA must either complete the necessary transmission modification on a timely basis or it must convene a technical meeting with the transmission customer to evaluate alternatives that are available to the customer (WAPA Tariff §20.1). If this review process determines that one or more alternatives exist to the originally planned construction project, then WAPA must present such alternatives for consideration by the customer (WAPA Tariff §20.2). If, upon review of any alternatives, the customer desires to maintain its application subject to construction of the alternative facilities, WAPA may revise the project to reflect the alternative. In the event that WAPA concludes that no reasonable alternative exists and the transmission customer disagrees, the customer may seek relief under codified dispute resolution procedures pursuant, or it may refer the dispute to the FERC for resolution.

Certain larger, non-exempt projects would also enter the NEPA process. The NEPA process provides opportunity for WAPA to compare alternatives to construction of new facilities. For example, in the Sacramento Area Voltage Support Final Environmental Impact Statement (September 2003), WAPA identified transmission route alternatives to avoid encroaching on a local cemetery and residential areas north of Sacramento. Other alternatives considered in the final NEPA document contained combinations of new construction and upgrades to existing lines. Non-transmission alternatives, such as encouraging development of generation in the area, were determined to be unfeasible during pre-project planning.

Case Study. In 1996, WAPA and the Sacramento Municipal Utilities District identified that load growth in Sacramento could result in possible future reliability problems. After forming the Sacramento Area Transmission Planning Group (SATPG), and conducting open public meetings, alternative solutions were identified, including encouraging development of new in-area generation. The proposals (now defunct) for new generation from Florida Power and Light at Rio Linda and Enron at Roseville as well as the construction of SMUD's Cosumnes Power Plant (currently under construction) would have partially addressed this need. After these projects were cancelled, WAPA pursued a non-generation alternative previously identified by SATPG, expansion of transmission facilities. This triggered the Sacramento Area Voltage Support proposal and subsequent NEPA process, which included its own alternatives assessment for identifying routes that were the least disruptive environmentally. The final NEPA document identified the O'Banion to Elverta transmission line as the preferred alternative in September 2003. The December 29, 2003 Record of Decision was published in the Federal Register (Vol. 69, No. 7) on January 12, 2004. Actual construction is contingent upon funding.

Definition. WAPA Tariff §1.14 defines Good Utility Practice as: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

D.4.2 Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Absent an RTO in the western states, a description of the transmission organization in the Pennsylvania-New Jersey-Maryland region is provided here for informational purposes.

The PJM Interconnection is a regional transmission organization that operates the wholesale electricity market across all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. As an RTO, PJM is responsible for planning the expansion of transmission capability on a regional basis. PJM follows a codified Regional Transmission Expansion Planning Protocol (RTEPP) that aims to meet the transmission needs of its members "on a reliable, economic, and environmentally acceptable basis." (Schedule 6, §1.1 of PJM

Operating Agreement). The annual Regional Transmission Expansion Plan reflects the anticipated transmission enhancements within a ten-year planning horizon, and, where appropriate, it outlines alternative means for meeting the transmission needs including possible non-transmission solutions (Schedule 6, §1.4). Development of the plan is conducted as an open process with input from power generators, customers, and other interested stakeholders.

D.4.3 Oregon Public Utility Commission and Department of Energy

Construction of new or expanded transmission lines of 230 kV or higher in Oregon requires a Site Certificate from the Oregon Department of Energy. This agency provides a "one-stop" licensing process for certifying construction of both generation and transmission facilities. The Department of Energy does not issue a Site Certificate to transmission projects unless the applicant appropriately demonstrates the need for the project (Division 23 of Oregon Energy Facility Siting Council Rules). Applicants seeking certification of generating facilities do not have to demonstrate need.

The Oregon Department of Energy requires each transmission line applicant to provide two alternative corridors in its application for the Site Certificate. Identifying non-transmission alternatives occurs during preceding planning processes that are under the jurisdiction of public utility commissions, which determine the need for transmission projects.

The need for transmission expansions can be determined by the Oregon Public Utility Commission or other public utility district in an Integrated Resource Plan, or least cost plan. The Integrated Resource Plans are periodically prepared by regulated utilities (e.g., Portland General Electric has filed six since 1990, most recently in 2002, and PacifiCorp filed a plan in January 2003). Oregon regulations require determining the most cost-effective solution for the ultimate consumer solution through a comparison of resources, facilities or conservation measures (ORS 469.010 and 469.310). Non-transmission options, such as distributed generation or demand management, could be identified and discussed by stakeholders during the integrated planning process, and they would be promoted by the Public Utility Commission if they would be the least-cost alternatives to transmission expansions (OPUC, 2004).

E. Renewable Energy Programs

Renewable electricity can provide fuel diversity, security, economic development, and environmental benefits. State policymakers have increasingly recognized these potential benefits through the creation of specific incentives and mandates for renewable energy. The Renewable Portfolio Standard (RPS) ensures that a minimum amount of renewable energy is included in the portfolio of electricity resources. It does so by requiring electric suppliers (e.g., IOUs) to include a minimum amount of renewables in their electricity supply. RPS, or RPS-like mandates, have been established in 13 U.S. states, including California (NGC, 2003). Because there is no single way to design an RPS, each of these states has crafted their policies differently. Though the majority of existing RPS policies have only recently been established, these policies have already begun to have an impact, especially for wind power, and over time their impact could be substantial.

California's RPS was established in 2002, and may be the most complex and aggressive of the state RPS policies. The IOUs must increase their renewable supplies by at least one percent per year starting January 1, 2003, until renewables make up 20 percent of their supply portfolios. The 20 percent requirement must be reached no later than 2017, but utilities may not have to meet the requirement if system-benefits charge (SBC) funds are exhausted before the requirement is met: costs of renewables over a to-be-determined market price must be paid for by the state's SBC fund. Competitive Energy Service Providers (ESPs) are required to start increasing renewables by 2006 or when their direct-access contracts expire, whichever comes first. Annual RPS purchase obligations begin when a utility has achieved creditworthy status, and IOUs are only obligated to purchase renewable energy to the extent sufficient SBC funds are available to cover any above-market costs of renewable resources.

In 2001, electricity sales by the IOUs totaled approximately 169,000 GWh. The RPS requires an annual increase in renewable generation equivalent to 1 percent of sales, or about 1,700 GWh. Accelerating the goals of SB 1078 to have 20 percent of retail sales procured from renewable energy sources by 2010 instead of 2017, would add 4,200 MW of renewables to the system over the next 7 years, at an average of 600 MW (1.6 percent) per year.

California's two largest utilities are already well on the way toward the 20 percent RPS requirement. SCE last year sold 12.5 billion kWh from renewable sources, for 17.7 percent of its total sales, and PG&E sold 8.2 billion kWh of renewables, for 11.5% of its sales. SDG&E only sold 547 million kWh of renewables, for 3.6% of its sales. But in 2004, the rulemaking proposes that SCE be required to sell 13.2 billion kWh, PG&E 8.92 billion kWh and SDG&E 697 million kWh from renewable sources. These annual procurement targets are the minimum amounts of renewable generation these utilities would have to procure each year, subject to the flexible compliance mechanisms. The utilities would be free to procure above their annual procurement targets and apply any excess generation to future years.

Eligible resources include: biomass, solar thermal electric, PV, wind, geothermal, fuel cells using renewable fuels, existing hydro under 30 MW, digester gas, landfill gas, ocean wave, ocean thermal, or tidal currents. New hydro is only eligible if it does not require new or incremental appropriations or diversions of water. Geothermal resources existing before September 26, 1996 are eligible only for adjusting a retail electric provider's baseline quantity of renewable energy, not for meeting the incremental one-percent requirements. Eligible biomass has fuel supply requirements. A restricted set of solid waste facilities is also eligible.

E.1 Examples of RPS in Other States

Below are examples of the RPS programs in Arizona and Nevada, two of the western states that border California and have implemented RPS policies.

Arizona. Arizona has a small, solar-focused RPS that began in 2001 and that has created some demand for new renewable energy in the state. Though well designed in some respects, uncertainty over the long-term fate of the policy and the lack of penalties are key weaknesses.

Arizona's RPS requirements include 0.2 percent in 2001, rising 0.2 percent per year to 1 percent in 2005, and to 1.05 percent in 2006, then to 1.1 percent for 2007-2012. At least 50 percent of the RPS must be new solar electricity through 2003, and at least 60 percent starting in 2004.

New is defined as being generation installed on or after January 1, 1997. Solar renewables include: PV and solar thermal electric. Non-solar renewables include: solar hot water and air conditioning, and in-state landfill gas, wind, and biomass. Solar hot water and solar air conditioning can contribute to the non-new solar portion of RPS if the provider contributed to the installation of the system. R&D investments can reduce the RPS target by up to 10 percent in 2001 and 5 percent in 2002-03. Customer-sited applications are eligible. Geothermal energy is not automatically eligible under the RPS.

Out-of-state solar is eligible if it is proven that the power reaches Arizona customers. Wind, landfill gas, and biomass must be instate. Renewable energy credit multipliers provide additional incentives for instate solar.

In 2003 the Arizona Corporation Commission (ACC) conducted a cost-benefit test to determine whether the RPS should continue to increase after 2004, or stay at 0.8 percent. The Working Group concluded that considerable progress had been made in just 18 months and that the EPS should be continued with two possible options: Option 1 would take no action at this time and would leave the annual renewable energy target at 0.8 percent of retail energy sales until a future review determines that either EPS funding is sufficient, or solar generation costs have declined to the point for EPS program success for all load serving entities (LSEs) at the 0.8 percent level, then increase the program percentage to 1.1 percent; or Option 2 would continue the renewable energy requirement increase to 1.1 percent by 2007.

The ACC accepted comments on the possible changes to the Environmental Portfolio Standard (EPS) and on April 5, 2004 held a second working group meeting to discuss possible developments and changes.

Nevada. Nevada's RPS began in 2003, and the utilities' first solicitation led to 130 MW of wind contracts, 97 MW of geothermal contracts, and 50 MW of solar contracts. With utility fears over wind power integration, geothermal is also poised to do well in future solicitations. The policy has already resulted in increased geothermal prospecting in the state, and has led to nearly 100 MW of new geothermal contracts. Nevada's RPS is among the most aggressive, and because it is applied in a regulated market, it is also a policy that will require a strong and ongoing role for the Nevada PUC. Utility financial problems may create some contracting difficulties, however.

Nevada's RPS requirements include 5 percent in 2003 and increasing by 2 percent every two years, ending at 15% in 2013 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane).

Resources that qualify include solar (including solar that offsets electricity, and perhaps even natural gas or propane), wind, geothermal and biomass (includes agricultural waste, wood, MSW, animal waste and aquatic plants). Legislation in 2003 adds electricity produced from certain forms of waste heat or pressure under 15 MW in size as eligible. Certain small hydro plants (including pumped hydro used at mines) under 30 MW in size are also now eligible, with limitations on water diversion, date of installation, and water use. On-site renewable generation qualifies. Distributed renewable generation receives extra-credit multiplier (1.15), except that customer-sited PV receives a far larger credit multiplier (2.4). Waste tire plants are not eligible, except that customer-sited waste tire facilities that use "reverse polymerization" qualify for 0.7 credits per kWh. If an IOU helps fund an end-user's solar thermal energy system that offsets electric use, then the IOU can count the consumption reduction against the RPS requirement.

Eligible renewables can be located instate or out-of-state with a dedicated transmission line to an in-state utility. The transmission line cannot be shared with more than one other nonrenewable generator.

E.2 Advantages and Disadvantages of Renewable Portfolio Standards

RPS policies in general have some potential theoretical advantages compared to other renewable energy policies, such as: (1) RPS can drive a known quantity of new renewable development and can ensure that there are buyers for that energy, (2) RPS may help lower the total cost of that development by giving IOUs the flexibility to meet their purchase targets in the way they deem best, and encouraging competition among renewable developers, (3) RPS can be competitively neutral if it is applied equally to all retail electricity suppliers, (4) RPS may impose relatively low administrative burdens and direct administrative costs on those responsible for overseeing the policy, and (5) RPS can be applied in both restructured and monopoly markets (NGC, 2003).

Potential disadvantages of RPS relative to other types of renewable energy policies include: (1) due to its complexity, the RPS can be difficult to design and implement well, (2) a RPS may be less flexible in offering targeted support to renewable energy than some of the other renewable energy policies, (3) the exact cost impacts of a

RPS cannot be known with certainty in advance, (4) operating experience with the RPS remains limited, (5) if an RPS does not lead to the availability of long-term power purchase agreements, the ability to finance new renewable projects will be limited and compliance costs may increase, and (6) an RPS is not necessarily suited to supporting diversity among renewable technologies, although a RPS can be designed to do so through the use of resource tiers and credit multipliers (NGC, 2003).

In addition to the RPS, several other state and federal policy approaches have been used to support renewable energy: integrated resource planning, tax incentives, renewable energy funds, encouragement of voluntary purchases of green power, and government purchases of renewable energy. Some of these policies may serve as alternatives to an RPS, while others might best be considered complements. Table B-2 lists the strengths and weaknesses of California's RPS policy in particular and Arizona and Nevada's as a source of comparison for other western states.

Table B-2. Strengths and Weaknesses of RPS Policies Designs

Strengths	Weaknesses
California	
• Supply-demand balance ensures substantial new renewables development • Broad applicability, with partial exemption to publicly owned utilities • Well defined and stable resource eligibility rules • Policy duration is sufficient • CPUC and Energy Commission given authority to develop effective enforcement, compliance flexibility, and verification • Detailed contracting standards and cost recovery mechanisms to be established • Legislation appeared to exclude out-of-state resources, but the Energy Commission has allowed those resources to qualify	• Policy design complexity and uncertainty • Decisions that might best be left to the market are instead made administratively in part because of use of SBC funds to support over-market costs • Availability of SBC funds may limit impact of policy • Exemption of non-creditworthy utilities may delay impact of policy, but unlikely to have major long-term effect
Arizona	

Table B-2. Strengths and Weaknesses of RPS Policies Designs

Strengths	Weaknesses
• Reasonable supply-demand balance ensuring some limited new supply, especially solar • Well defined and stable resource and geographic eligibility rules • Reasonably broad application, with some exemptions • Adequate verification and compliance flexibility • Cost recovery mechanisms exist for utilities	• Uncertainty in duration and stability of targets due to 2003 evaluation of policy • Lack of enforcement and non-compliance penalties has resulted in significant under-compliance with the standards • Unclear eligibility of geothermal resources • Legality of in-state restriction for some resources is unclear • Company based application of RPS and even encouragement of green power sales to meet RPS
Nevada	
• Supply-demand balance ensures substantial new renewables development • Reasonably broad applicability, with exemption for publicly owned utilities • Well defined and stable resource and geographic eligibility rules • Duration and stability of targets appear strong • Adequate verification and compliance flexibility • Contracting standards and cost recovery mechanisms	• Legality of geographic requirements is unclear • Aggressive purchase requirements may strain resource availability in the long term • Supply-demand balance weakness in early years, with insufficient lead time to bring new renewables on line • Vague noncompliance penalties not yet a concern, but could become an issue in the future • Eligibility recently expanded via legislation

Source: NGC, 2003.

E.3 California's Renewable Portfolio Standard Authority

In California, a great deal of authority is given to the CPUC and Energy Commission to design the RPS policy, including (1) defining the benchmark price above which the systems-benefits charges (SBC) will cover the above-market cost of renewable purchases, and (2) establishing a least-cost, best-fit process to select winning renewable energy bidders. In an order Administrative Law Judge (ALJ) Charlotte TerKeurst (I.00-11-001), the CPUC is working with the investor-owned utilities (IOUs) and other stakeholders, such as The Utility Reform Network (TURN), Center for Energy Efficiency and Renewable Technologies (CEERT), and California Wind Energy Association (CalWEA), to develop an interim methodology to assess transmission costs and establish this process.

Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002) requires that the Energy Commission and the CPUC work collaboratively to implement the RPS and assigns specific roles to each agency. The CPUC and the Energy Commission have developed a schedule for addressing RPS issues, and have established guidelines for how the two agencies work collaboratively on the RPS. The schedule and collaborative process are described in the Energy Commission's Committee Order on RPS Proceeding and CPUC's Collaborative Guidelines. The Order also describes administrative procedures for interested parties who wish to participate in the Energy Commission's RPS proceeding. The roles of the Energy Commission and the CPUC are briefly summarized below.

California Energy Commission. Pursuant to SB 1078, the Energy Commission's responsibilities include:

- Certifying eligible renewable resources that meet criteria contained in the bill, including those generating out-of-state.
- Designing and implementing a tracking and verification system to ensure that renewable energy output is counted only once for the purpose of the RPS and for verifying retail product claims in California or other states.
- Allocating and awarding supplemental energy payments as specified in SB 1038 to eligible renewable energy resources to cover above-market costs of renewable energy.

At its regularly scheduled Business Meeting on March 5, 2003, the Energy Commission adopted Order No. 03-0305-04 authorizing the Renewables Committee to oversee implementing the RPS under SB 1078 and SB 1038. On March 14, 2003, the Renewables Committee issued an order initiating the RPS Proceeding under Docket No. 03-RPS-1078 and establishing a proposed schedule and process for addressing issues.

California Public Utilities Commission. The CPUC, in collaboration with the Energy Commission, has initiated a proceeding to implement the state's RPS as mandated by Senate Bill 1078 under Public Utilities Code sections 381, 383.5, 399.11 through 399.15, and 445. The CPUC is addressing its responsibilities in implementing the RPS through a separate proceeding titled, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development (R.01-10-024). The CPUC's responsibilities include:

- Establishing a process to determine market price referents, setting the criteria for IOU ranking of renewable bids by least cost and best fit, and establishing flexible compliance rules, penalty mechanisms and standard contract terms and conditions.
- Establishing initial renewable generation baselines for each IOU, making subsequent changes to these baselines as needed, and determining annual procurement targets (APTs).
- Directing the IOUs to develop procurement plans, and approving, amending or rejecting the plans.
- Making specific determinations of market price referents for products under contract.
- Approving or rejecting IOU requests to enter specific contracts for renewable power, including determining if a solicitation was adequately competitive.
- Factoring transmission and imbalance costs into the RPS process and identifying the transmission grid implications of renewable development.
- Defining rules for the participation of renewable Distributed Generation (DG), Electric Service Providers (ESP), Community Choice Aggregators (CCA), and potential Procurement Entities.

Assembly Bill (AB) 970 requires the Energy Commission to identify constraints in California's transmission and distribution system and to take actions to remove them. As mentioned above, the CPUC issued an Order Instituting Investigation (I.00-11-001) into implementation of AB 970 regarding the identification of electric transmission and distribution constraints, actions to resolve those constraints, and related matters affecting the reliability of electric supply in March 2004. The ALJ order discusses the development and consideration of indirect transmission costs in assessing RPS bids. The initial focus in this phase is on the development of an interim methodology to estimate and consider transmission costs for use during the initial RPS procurement.

There was agreement at the pre-hearing conference (PHC) that the utilities should prepare their transmission cost estimates based on the most recent existing conceptual transmission studies, including the studies prepared for Senate Bill 1038 compliance and submitted on August 31, 2003 in this proceeding. Each proposed developer should provide basic interconnection information in this proceeding for the utilities' use in developing transmission cost estimates. Prior solicitations have yielded much of this information but that a supplemental solicitation is needed and that additional conceptual studies may be needed based on solicitation results.

In April 2004, the ALJ has prepared a proposed interim methodology for development and consideration of transmission costs during the initial RPS procurement and is currently accept comments on it. After receipt of comments and reply comments on the interim methodology, the ALJ plans to prepare a draft decision, which will be served on parties and subject to review and comment prior to issuance of a CPUC decision.

To enable the first round of RPS solicitations to occur on July 1, the CPUC on April 22, 2004 unanimously approved a rulemaking (R.04-04-026) setting mandatory interim procurement targets for each of the state's big three IOUs. The commissioners are slated to consider an order in June 2004 setting annual procurement targets based on the accelerated Energy Action Plan goal. In order to meet this goal, the CPUC will consider increasing the annual procurement targets for each utility beginning in 2005. The CPUC's immediate goal is to ensure that the utilities will be able to issue Requests for Offers (RFOs) by July 1, 2004, and that renewable generators will be able to prepare and submit bids in response to those RFOs.

To that end, the rulemaking sets baseline levels of renewable generation for each utility as a proportion of each utility's total generation portfolio, and sets an interim annual procurement target that each utility must meet this year. Quantifying the amount of renewable generation in each utility's present portfolio will set the baseline. The rulemaking sets interim baseline quantities and a market price reference methodology. Comments on both are due on April 30. The baseline represents the amount of renewable generation a utility must retain in its portfolio to continue to satisfy its obligations under the RPS targets of previous years. The incremental procurement target is at least 1 percent of the previous year's total retail electrical sales, including power sold to a utility's customers from Department of Water Resources (DWR) contracts. "In short, the amount of generation together is what the utility must procure in order to satisfy its annual RPS obligation," the order stated. The commission has already approved 22 renewable contracts from the transitional procurement activity.

The CPUC delegated other tasks and issues to be addressed as it gains more experience with the program, and as the renewable generation industry continues to evolve. "In order to meet our immediate objective of an RPS solicitation as soon as possible, however, there are specific tasks that the CPUC must complete or at least move close to resolution," the CPUC stated.

The CPUC will use the rulemaking process to adopt standardized contract terms and conditions, define a renewable energy credit, finalize the market price reference methodology and further develop a "least-cost and best-fit" evaluation process for ranking the bids of renewables projects. The commissioners are expected to consider an order in June to establish a market price reference to compare renewables offers to other sources of supply and demand side resources. The evaluation will include other tasks, such as the development of transmission adders, capacity values and integration costs.

F. Integrated Resources Planning

Traditional utility resource planning involves forecasting load growth and assessing various supply options to meet that load growth at the lowest possible cost, while maintaining reliability. Integrated resource planning (IRP) emerged in the 1980s as an analytic means of incorporating demand-side resources (i.e., energy efficiency and load management) into resource planning, as well as incorporating other factors such as uncertainty and environmental quality (NGC, 2003). IRP allows a portfolio approach to minimizing costs, subject to reliability requirements, and can incorporate environmental and diversity factors as well. IRP is best suited to a regulated monopoly context. It is challenging to apply conventional IRP principles in restructured markets where ratemaking authority for new entrants has been ceded to market forces, especially when generation has been divested and there are no stable utility portfolios. In fact, RPS policies (see Appendix sections, above) have frequently been adopted (in part) to replace IRP during the transition to restructured electricity markets. As a result, in regulated markets, IRP and RPS approaches may be thought of as substitutes in some circumstances, but this is not the case in restructured markets.

The concepts of IRP can be used in development of alternatives to transmission expansions, as long as all market participants are involved in the process. Involvement of grid operators would be necessary to ensure reliability and feasibility of options. Involvement of customers would be necessary to identify opportunities for demand management, and a fully-integrated process would involve environmental or community interests. Project proponents could provide information on costs for economic comparisons. Optimally, any integrated planning approach would occur in the public forum, enabling participation of the varied interests.

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Acronyms and Abbreviations

AB. Assembly Bill.
ALJ. Administrative Law Judge.
ALP. Alternative Licensing Process.
BLM. Bureau of Land Management.
BPA. Bonneville Power Authority.
CAES. Compressed Air Energy Storage.
CA ISO. California Independent System Operator.
CalSEIA. California Solar Energy Industries Association.
CalWEA. California Wind Energy Association.
CBC. California Biomass Collaborative.
CCA. Community Choice Aggregators.
CEERT. Center for Energy Efficiency and Renewable Technologies.
CEQA. California Environmental Quality Act.
CHP. Combined Heat and Power.
COI. California-Oregon Intertie.
CPA. California Consumer Power and Conservation Financing Authority.
CPCN. Certificate of Public Convenience and Necessity.
CPUC. California Public Utilities Commission.
CSP. Concentrating Solar Power.
DFG. Department of Fish and Game.
DG. Distributed Generation.
DOE. Department of Energy.
DSM. Demand-Side Management.
EA. Environmental Assessment.
EAP. Energy Action Plan.
EIR. Environmental Impact Report.
EIS. Environmental Impact Statement.
EMF. Electric and Magnetic Field.
EOB. Electricity Oversight Board.
ESP. Electric Service Providers.
EVMWD. Elsinore Valley Municipal Water District.
FERC. Federal Energy Regulatory Commission.
FLR. Fixed Load Reduction.
FPL. Florida Power & Light.
GGF. Grid Generating Facilities.
GIS. Geographic Information System.
GWh. Gigawatt-Hour.
IEPR. Integrated Energy Policy Report.
IOU. Independent-Owned Utility.
IPP. Independent Power Producer.
IS. Initial Study.
kV. Kilovolt.
kW. Kilowatt
LADWP. Los Angeles Department of Water and Power.
LARS. Local Area Reliability Service.
MCFC. Molten Carbonate Fuel Cell.

MND. Mitigated Negative Declaration.
MOU. Memorandum of Understanding.
MSC. Market Surveillance Committee.
msl. Mean Sea Level.
MSW. Municipal Solid Waste.
MW. Megawatt.
NEPA. National Environmental Policy Act.
NERC. North American Electric Reliability Council.
NOC. Notice of Construction.
NOP. Notice of Preparation.
OIR. Order Instituting Rulemaking.
OTEC. Ocean Thermal Energy Conversion.
PAFC. Phosphoric Acid Fuel Cell.
PEMFC. Proton Exchange Membrane Fuel Cell.
PG&E. Pacific Gas & Electric.
PHC. Pre-Hearing Conference.
PLMP. Peak Load Management Project.
PTC. Permit to Construct.
PTO. Participating Transmission Owner.
PV. Photovoltaic Systems.
QFs. Qualifying Facilities.
RFO. Requests For Offers.
RFP. Request for Proposals.
RMR. Reliability Must-Run.
ROD. Record of Decision.
ROW. Right-of-Way.
RPS. Renewable Portfolio Standard.
RTG. Regional Transmission Groups.
RTO. Regional Transmission Organizers.
SB. Senate Bill.
SBC. Systems-Benefits Charges.
SCE. Southern California Edison.
SCIT. Southern California Import Transmission.
SDG&E. San Diego Gas & Electric.
SDREO. San Diego Regional Energy Office.
SMUD. Sacramento Municipal Utility District.
SOFC. Solid Oxide Fuel Cell.
SPPCo. Sierra Pacific Power Company.
SSG-WI. Seams Steering Group—Western Interconnection.
STEP. Southwest Transmission Expansion Plan.
SWPL. Southwest Power Link
TEAM. Transmission Economic Assessment Methodology.
TURN. The Utility Reform Network.
UARP. Upper American River Project.
USFS. United States Forest Service (U.S. Department of Agriculture).
USGS. United States Geological Survey.
VLR. Variable Load Reduction.
WAPA. Western Area Power Administration.

WECC. Western Electricity Coordinating Council.